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Emissions and Cost Estimates for Globally Significant Anthropogenic Combustion Sources of NOx, N2O, CH4, CO, and CO2

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EMISSIONS AND COST ESTIMATES FOR GLOBALLY SIGNIFICANT ANTHROPOGENIC COMBUSTION SOURCES OF NO_x, N_2O, CH_4, CO, and CO_2

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16. ABSTRACT The report discusses the development of emission factors for CO2, CO, CH4, NOx, and N2O for about 80 globally significant combustion sources in seven source categories: utility, industrial, fuel production, transportation, residential, commercial, and kilns/ovens/dryers. Because of the lack of adequate international data, the emission factors for most sources are based on U.S. performance, cost, and emissions data. Data on CO2, CO, and NOx were available for over 90% of the sources studied; on CH4, for about 80%; and on N2O, for only about 10%. Emission factor quality ratings were developed to indicate the overall adequacy of the supporting data. Quality ratings ranged from A to E, with A the best. Except for N2O, the emission factors for the gases covered the quality spectrum from A to E; all of the emission factors for N2O were rated E. Evaluation of the emission factors for the seven source categories (taking the five gases as an aggregate for each category) showed that the kilns/ovens/dryers category had the lowest overall quality rating; no factors rated better than E. Emission factors for fuel production were somewhat better, but generally of lower quality than for the remaining five source categories.

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Emission	Nitrogen Oxides	Stationary Sources	14G	
Cost Estimates	Nitrogen Oxide (N_2O)	Emission Factors	05A, 14A	
Combustion			21B	
Carbon Dioxide			07B	
Carbon Monoxide				

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ABSTRACT

Emission factors for carbon dioxide (CO_2), carbon monoxide (CO), methane (CH_4), nitrogen oxides (NO_x), and nitrous oxide (N_2O) were developed for about 80 globally significant combustion sources in 7 source categories -- utility, industrial, fuel production, transportation, residential, commercial, and kilns/ovens/dryers. These factors were prepared for use by EPA in estimating global emissions of these gases for a Report to Congress on policy options for stabilizing global climate. Because of the lack of adequate international data, the emission factors for most sources are based on U.S. performance, cost, and emissions data. Data on CO_2, CO, and NO_x were available for over 90 percent of the sources studied; on CH_4, for about 80 percent; on N_2O, for only about 10 percent. Emission factor quality ratings were developed to indicate the overall adequacy of the supporting data. Quality ratings ranged from "A" to "E", and "A" being the best. Except for N_2O, the emission factors for the gases covered the quality spectrum from A to E; all of the emission factors for N_2O were given an "E" rating. Evaluation of the emission factors for the 7 source categories (taking the 5 gases as an aggregate for each category) showed that the kilns/ovens/dryers category had the overall lowest quality rating, with no factors given better than a "B" rating. Emission factors for fuel production were somewhat better, but generally of lower quality than those for the remaining 5 source categories.

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SECTION 1
INTRODUCTION AND SUMMARY

The U.S. Environmental Protection Agency (EPA) has been asked by Congress under the National Climate Program Act to report on the environmental effects of global climate change and the options available to the global community to mitigate and adapt to potential global warming. The U.S. National Climate Program established by the National Climate Program Act involves several agencies and organizations engaged in interdisciplinary analysis of global climate and related issues. Within EPA, several programs have been established to perform the work necessary for supporting the National Climate Program and to provide the analysis and assessments necessary for the reports to Congress. EPA's Air and Energy Engineering Research Laboratory (AEERL) is supporting the technical effort required to estimate a global greenhouse gas emission inventory and to identify options to reduce these emissions. The technical effort includes development of emission, efficiency, and cost estimates for globally significant greenhouse gas emission sources and development of performance and cost estimates for emission control technologies.

Rapid expansion of global population and industrial activity have dramatically increased the emissions of gases and pollutants that are referred to as greenhouse gases. Greenhouse gases transmit solar radiation and absorb infrared radiation, as does the glass in a greenhouse, and could result in significant increases in the global average surface temperature. In the report to Congress, several atmospheric trace gases are to be evaluated. The gases considered are CO_2, CO, CH_4, NO_x, and N_2O, which are considered greenhouse gases or are precursors for atmospheric chemical reactions that produce greenhouse gases. The concentrations of these five gases are currently increasing due to both anthropogenic and biogenic emission sources.

Anthropogenic emission sources include combustion and noncombustion sources. The combustion of fossil fuels is generally considered the major cause of increasing atmospheric CO_2 and CO concentrations. Fuel combustion is also responsible for significant emissions of NO_x, which consists of both NO and NO_2. NO_2 and NO are not greenhouse gases, but they are precursors to the formation of ozone, an active greenhouse gas in the troposphere. Although the emissions of N_2O from combustion are small on a mass basis when compared to the emissions of CO_2, N_2O is over 250 times more effective than CO_2 in adsorbing infrared radiation (Weiss, 1981).

The purpose of this effort is to develop emission factor estimates and other data for combustion sources of greenhouse gases. The emission factors developed for this report are intended for use in estimating a global emission inventory of CO_2, CO, CH_4, NO_x, and N_2O. To provide options for stabilization and reduction of emissions of these gases, emission control technologies are identified for the combustion sources. The emission reduction capabilities of emission control technologies can be incorporated into developing a global emission inventory and into forecasting global emissions under various scenarios.

SCOPE

This project is limited to the evaluation of significant combustion sources of greenhouse gases. Only sources and controls for which data are readily available are included in this report. Performance and cost estimates for advanced combustion technologies and controls and for noncombustion sources and controls were not included in this study.

Anthropogenic Sources Included in the Study

An initial list of roughly 90 combustion sources was developed as a starting point for the collection of emission and control technology data. This list is given in Table 1. After a review of the available literature and discussions with various experts, the list was revised to roughly 80 sources, given in Table 2.

The utility sources in Table 2 are the same as those in Table 1. The industrial boiler category was modified because data were not readily available for the population of high versus low efficiency boilers, nor were emission factors readily available for industrial boilers categorized based on efficiency. The different coal-fired industrial boiler technologies in Table 1 are represented by a single coal-fired industrial boiler category in Table 2. Distillate oil-fired boilers were not included in Table 2. Fired heaters were added as part of the fuel production category because they are an integral part of the petroleum refining process. The initial listing of

TABLE 1. PRELIMINARY LIST OF COMBUSTION SOURCES OF GREENHOUSE GASES

Major Categories	Subcategories
Utilities	Gas - boiler
	Gas - combined cycle
	Gas turbines
	Residual oil
	Distillate oil
	Shale oil
	Municipal waste - mass feed
	Municipal waste - refuse-derived fuel
	Coal - spreader stoker
	Coal - fluid bed - combined cycle
	Coal - fluid bed - boiler
	Coal - pulverized coal - cyclone
	Coal - pulverized coal - tangential
	Coal - wall fired
	Wood
Industrial Boilers	Wood
	Gas - low thermal efficiency
	Gas - high thermal efficiency
	Residual - low thermal efficiency
	Residual - high thermal efficiency
	Distillate - low thermal efficiency
	Distillate - high thermal efficiency
	Municipal waste
	Refuse-derived fuel
	Coal - fluid bed
	Coal - spreader stoker - low thermal efficiency
	Coal - spreader stoker - high thermal efficiency
	Coal - pulverized coal
	Coal - mass stoker
	Bagasse/agricultural waste
Fuel Production	Gas production & refining
	Oil production & refining - w/CH$_4$ wastage
	Oil production & refining - w/o CH$_4$ wastage
	Coal production & cleaning
	Oil shale production & refining
	Coal gasification - current technology
	Coal gasification - advanced technology
	Coal liquefaction
	Charcoal production

TABLE 1. (Continued)

Major Categories	Subcategories
Transportation	Rail Jet aircraft Ship Aviation gasoline Gasoline - light duty - pre-control Gasoline - light duty - post-control Gasoline - heavy duty Gasoline - light duty Diesel -light duty Diesel - heavy duty Methanol - light duty Methane - light duty Internal combustion engines - diesel pipeline transportation Internal combustion engines - gas pipeline transportation Gas turbines
Residential/Commercial	Direct fired - wood pits Direct fired - wood fireplace Direct fired - wood stove - old/modern Direct fired - gas heater - old Direct fired - gas heater - modern (pulse) Direct fired - oil - old Direct fired - oil - modern Direct fired - coal fireplace Direct fired - coal stove Direct fired - coal central heat Direct fired - propane/butane
	Boilers - wood Boilers - gas Boilers - residual oil Boilers - distillate oil Boilers - municipal waste Boilers - coal Boilers - shale
	Waste reduction - open burning - municipal waste Waste reduction - open burning - agricultural Waste reduction - incineration - low efficiency Waste reduction - incineration - high efficiency

TABLE 1. (Continued)

Major Categories	Subcategories
Heaters/Furnaces/Kilns/Ovens/Dryers	High temperature - distillate oil High temperature - gas High temperature - residual oil High temperature - coal High temperature - shale oil
	Intermediate temperature - distillate oil Intermediate temperature - gas Intermediate temperature - residual oil Intermediate temperature - coal Intermediate temperature - shale oil
	Low temperature - distillate oil Low temperature - gas Low temperature - residual oil Low temperature - coal Low temperature - shale oil

TABLE 2. REVISED LIST OF COMBUSTION RELATED EMISSION SOURCES

UTILITY

- Natural Gas Boilers
- Gas Turbine Combined Cycle - Natural Gas
- Gas Turbine Simple Cycle - Natural Gas
- Residual Oil Boilers
- Distillate Oil Boilers
- Shale Oil Boilers
- Municipal Solid Waste - Mass Feed
- Municipal Solid Waste - Refuse Derived Fuel
- Coal - Spreader Stoker
- Coal - Fluidized Bed Combined Cycle
- Coal - Fluidized Bed
- Coal - Pulverized Coal Cyclone Furnace
- Coal - Pulverized Coal Tangential Fired
- Coal - Pulverized Coal Wall Fired
- Wood-Fired Boilers

INDUSTRIAL

- Coal-Fired Boilers
- Residual Oil-Fired Boilers
- Natural Gas-Fired Boilers
- Wood-Fired Boilers
- Bagasse/Agricultural Waste-Fired Boilers
- Municipal Solid Waste - Mass burn
- Municipal Solid Waste - Small modular

FUEL PRODUCTION

- Natural Gas Refining
- Catalyst Regeneration
- Refinery - Natural Gas Waste Flared
- Refinery - Natural Gas Waste Used
- Coal Dryer
- Oil Shale - Surface Retorting
- Oil Shale - In-Situ Retorting
- Lurgi Coal Gasification
- Coal Liquefaction - Acid Gas
- Charcoal Production
- Waste Flare - Pure Methane
- Waste Flare - Natural Gas
- Fired Heater - Natural Gas
- Fired Heater - Process Gas
- Fired Heater - Distillate Oil
- Fired Heater - Residual Oil

TABLE 2. (Continued)

TRANSPORTATION

- Rail
- Jet Aircraft
- Aviation--Gasoline
- Ships
- Light Duty Gasoline Vehicle
- Heavy Duty Gasoline Vehicle
- Light Duty Diesel Vehicle
- Heavy Duty Diesel Vehicle
- Light Duty Methanol Vehicle
- Light Duty Compressed Natural Gas Vehicle
- Internal Combustion Engine-Diesel (Pipeline)
- Internal Combustion Engine--Natural Gas (Pipeline)
- Gas Turbine - Natural Gas (Pipeline)

RESIDENTIAL

- Wood Pits
- Wood Fireplaces
- Wood Stoves
- Propane/Butane Furnace
- Coal Hot Water Heater
- Coal Furnaces
- Coal Stoves
- Distillate Oil Furnaces
- Natural Gas Heaters

COMMERCIAL

- Wood Boilers
- Natural Gas Boilers
- Residual Oil Boilers
- Distillate Oil Boilers
- Municipal Solid Waste Boilers
- Coal Boilers
- Shale Oil Boilers
- Open burning - Municipal Solid Waste
- Open burning - Agricultural
- Incinerator - Multi-stage
- Incinerator - Single Chamber

TABLE 2. (Continued)

KILNS/OVENS/DRYERS

Kilns - Natural Gas (Cement or Lime Kiln)
Kilns - Oil (Cement or Lime Kiln)
Kilns - Coal (Cement or Lime Kiln)
Coke Oven - Coke Oven Gas
Dryer - Natural Gas
Dryer - Oil
Dryer - Coal

transportation sources is unchanged in the revised listing with the exception of the deletion of post-control light duty vehicles; the effect of control technologies for light duty vehicles is estimated as part of the control technology performance estimates. The original residential and commercial category was divided into separate categories. The sources within these categories for the original list are included in the revised list; however, no data were readily available to distinguish the performance of old from modern residential sources, so this distinction is not made in the revised table. Insufficient data were readily available to justify the subdivision of kilns, ovens, and dryers based on operating temperature, and no data were readily available from which to estimate emissions of these sources from the combustion of shale oil.

Type of Data Collected

Table 3 indicates the format of the source performance and cost data presented in this report. The data for each of the emission sources include the energy conversion efficiency for utility, industrial boiler, residential, commercial, and fuel production sources, and for kilns, ovens, and dryers. Plant costs were developed for utility and industrial boiler sources, and were levelized on an energy input or energy output basis depending on the availability of an efficiency estimate. Emission factors were developed on an energy output basis for utility, industrial boiler, and commercial sources, and for some other sources where applicable efficiency data were available. Emission factors for the remaining sources were developed on an energy input basis, with the exception of some fuel production sources, for which emission factors were developed based on crude oil production. All of the combustion technologies considered in this project are currently available.

For each emission source in Table 2, an effort was made to identify applicable emission control technologies. Most of the control technologies included in this report are currently available. However, some advanced control technologies were included in this study to provide an option for more stringent control of a specific greenhouse gas or, in the case of advanced utility controls for CO_2, to provide an option for controlling a gas that cannot be reduced by current methods.

TABLE 3. COMBUSTION EMISSION SOURCE DATA FORMAT

Emission Source Technology	Efficiency (%)	Cost ($/joule)	Emissions (kg/joule)					Applicable Control Technology Codes
			CO_2	CO	CH_4	H_2O	NO_x	
	Utility eff. = fuel heat value/ electricity delivered to user.	Joule = energy delivered to user.	Joule = energy delivered to user except transportation and kiln/oven/dryer where joule is fuel heating value. Emissions = uncontrolled emissions.					
	Industrial and residential eff. = fuel energy in/ energy delivered to user.	$ = cost in 1985 excluding fuel costs.						

The general format of the control technology performance and cost data is presented in Table 4. For control technologies, an efficiency penalty on the combustion technology was estimated, as was the removal efficiency for the five greenhouse gases considered in this study. Emission control costs were developed on an energy input or energy output basis, depending on the basis for the combustion technology cost. For each control technology, an availability date was estimated.

The emission factors developed in this report represent sources without control technologies. To calculate the baseline global emission inventory for the regions of the world, appropriate controls can be applied to specific source categories to represent the current application of control technologies in some countries. This report does not attempt to identify which controls should be applied to represent current control levels in different parts of the world. This is the subject for a study in itself.

Data Quality

For each emission factor, a data quality rating was assigned to indicate the relative quality of the emission factors within this database. The data quality ratings can also be used to identify areas that could benefit from additional research. A few of the factors that affect the quality of an emission factor include the quality of the emission data, which are typically available on the basis of mass of pollutant emitted per mass of fuel burned, the quality of the fuel properties used to convert the emission factor to an energy basis, and the quality of efficiency estimates used to convert the emission factor to an end-use energy basis. The emission data may be subject to variability due to variations in the design, operation, and maintenance at specific sources. These factors were taken into consideration when assigning emission factor ratings.

Report Format

A more complete discussion of the general approach used to develop performance and cost estimates for combustion sources and emission control technologies and of the basis for the emission factor quality ratings is given in Section 2. Sections 3 through 8 present the performance and cost estimates

TABLE 4. EMISSION CONTROL TECHNOLOGY DATA FORMAT

Control Technology	Device Code	Efficiency Penalty[a] (%)	Cost ($/joule)	Availability (date)	Performance (% reduction)				
					CO_2	CO	CH_4	H_2O	NO_x
		Expressed as % of combustion device efficiency	Cost = 1985 $						

[a] May be a benefit in some cases.

for emission sources and control technologies within the utility, industrial boiler, kilns, ovens, and dryers, fuel production, mobile source, and residential and commercial categories. The specific methods used to develop performance and cost estimates for each source category are discussed in the appropriate section. The results of the study are summarized below.

SUMMARY

For this study, performance and cost estimates were developed for globally significant combustion sources of CO_2, CO, CH_4, NO_x, and N_2O and for applicable emission control technologies. Although the intent of this work was to develop globally representative estimates, international performance and cost data were not readily available for most of the sources and controls. In many cases, data were not available from which to estimate the emission factors of all five of the gases for a given source; in particular, few data are available from which to estimate emission factors for N_2O. The emission factors for CO_2 were generally calculated from a carbon balance.

For most sources and control technologies, the performance and costs are based on U.S. data. The emission data developed under various EPA projects represent the most extensive, highest quality, and most accessible information available from which to calculate source emission factors, efficiency, and cost, as well as emission control removal efficiency, efficiency penalty, and cost. Although data are available from the United Nations to estimate global fuel consumption and in some cases energy conversion efficiency, the data readily available from the United Nations Statistical Office and Environment Programme are not suitable for a disaggregated analysis (i.e. few data are available for specific combustion technologies). However, the United Nations data can be used to estimate, for example, the overall energy conversion efficiency of all utility sources in various geopolitical regions of the world. The Organization for Economic Cooperation and Development (OECD) has addressed global fuel consumption and environmental issues, but again the data available from the OECD do not directly support the development of source specific emission factors. The use of source-specific U.S. data was generally required due to the absence of readily available data from international sources; however, in many cases the U.S. data may be globally representative of the energy-specific emissions of the five greenhouse gases considered in this study.

The emission factor quality ratings are summarized in Figures 1 through 4 to indicate the overall quality of this emission factor database. The emission factors were given quality ratings from "A" to "E," with an "A" being the best. Figure 1 indicates that the distribution of the ratings is fairly even; roughly 35 percent of all emission factors have a rating of "B" or higher, while about 39 percent of the emission factors have a rating of "D" or lower.

Figure 2 shows the percentage of the total number of emission factors for each of the five gases for which data were not readily available. The figure indicates that in general data were readily available for NO_x and CO. For nearly all sources it was possible to calculate CO_2 emission factors using a carbon balance. The carbon balance generally accounts for the conversion of carbon in the fuel to CO_2, CO, and CH_4. In many cases, the emission factors for CO_2 are orders of magnitude greater than for any other carbonaceous species. Therefore, it was possible to estimate with reasonable accuracy CO_2 emission factors for many sources for which CO and/or CH_4 emission factors were not available. For this reason, the percent of CO_2 emission factors for which data was not readily available is less than the percent of CO and CH_4 emission factors for which data was not readily available.

Only limited data were readily available from which to estimate N_2O emission factors. For approximately 90 percent of the sources included in this study, data were not available from which to estimate an N_2O emission factor.

Figure 3 indicates the overall quality of the available emission factors for each of the five gases. The N_2O quality rating of "E" for all N_2O emission factors reflects the lack of sufficient test data from which to develop high quality emission factors. The emission factors for CH_4, many of which were estimated based on a percentage of total hydrocarbon emissions, generally have lower ratings than CO and NO_x emission factors. The emission factors for CH_4 tend to be smaller in magnitude compared to NO_x or CO emission factors. The distributions of ratings for NO_x and CO emission factors are fairly uniform. The emission factors for CO_2 were generally given higher quality ratings than the other four gases, even though CO_2 emission factors were generally calculated from a carbon balance. CO_2 represents the largest

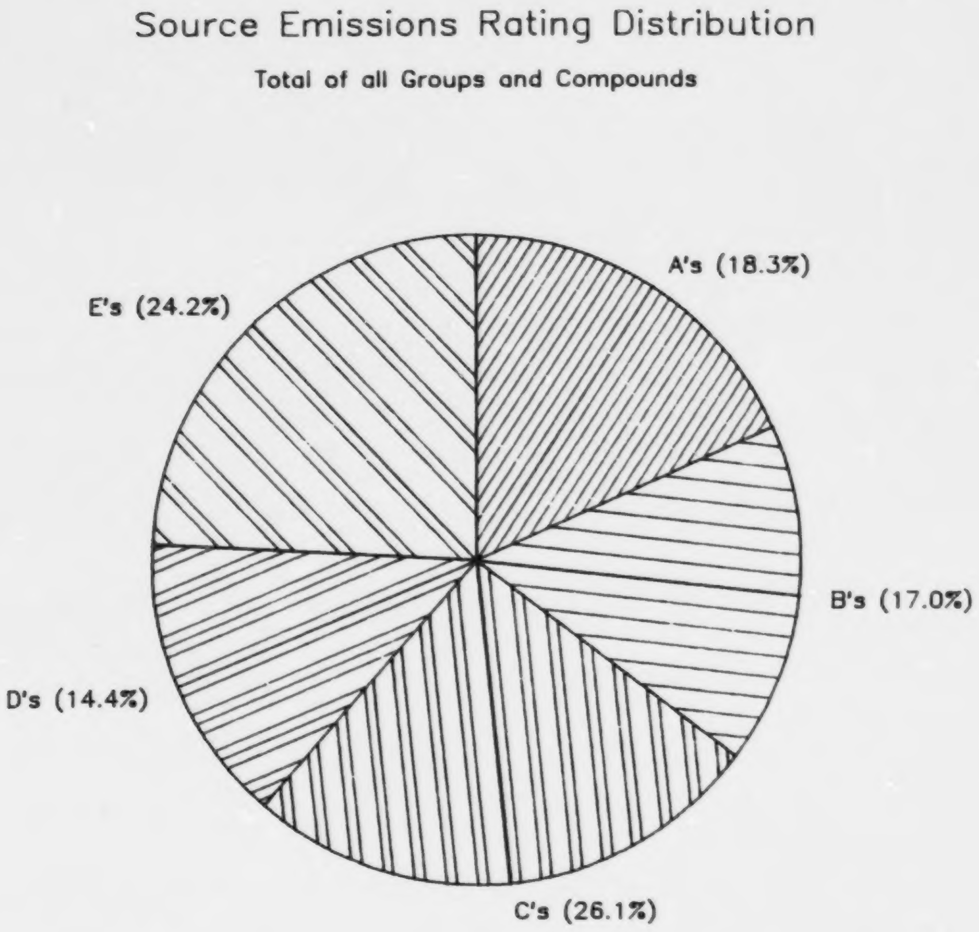

Figure 1. Distribution of all emission factor quality ratings.

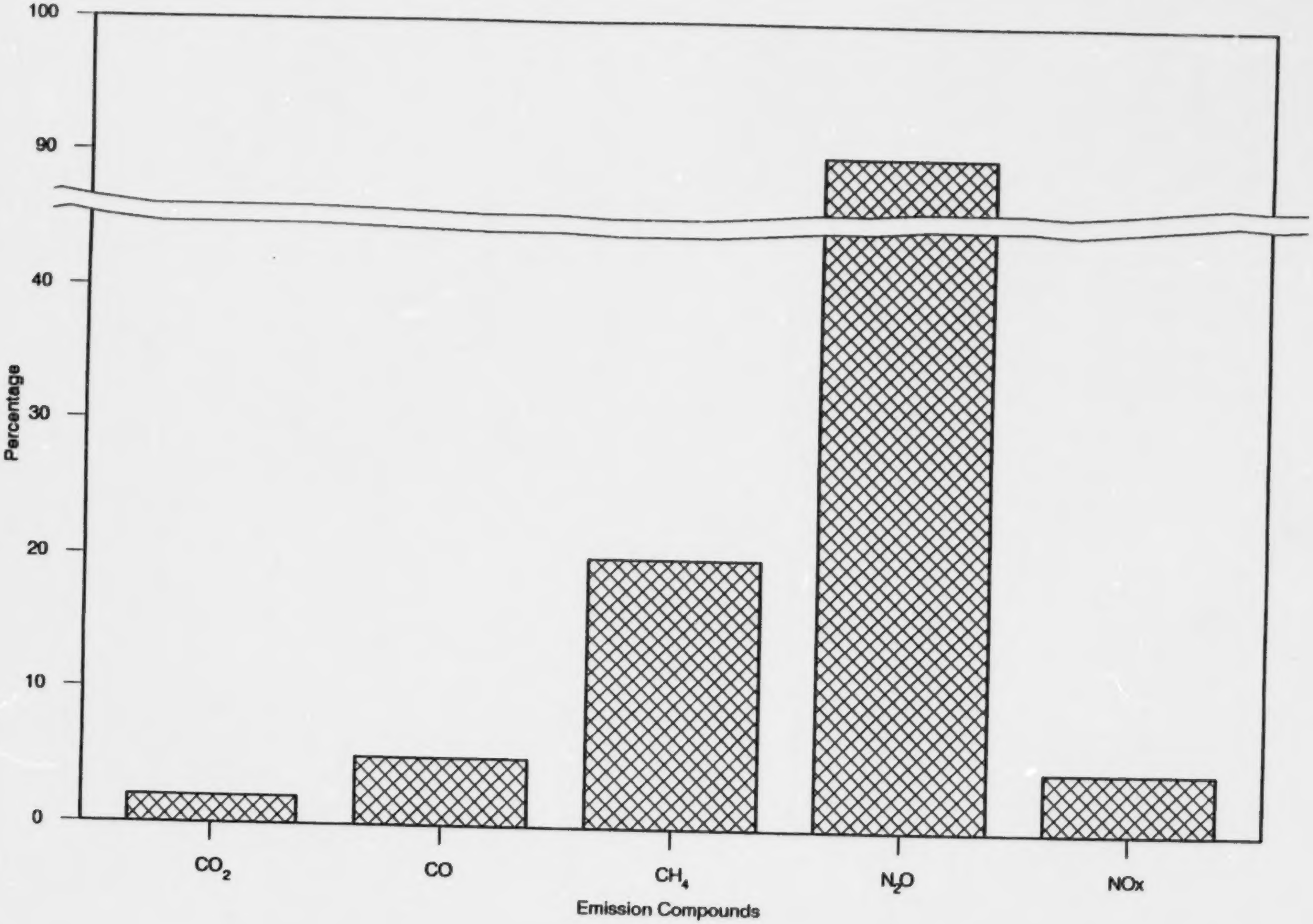

Figure 2. Percent of emission factors for each gas for which data was not readily available.

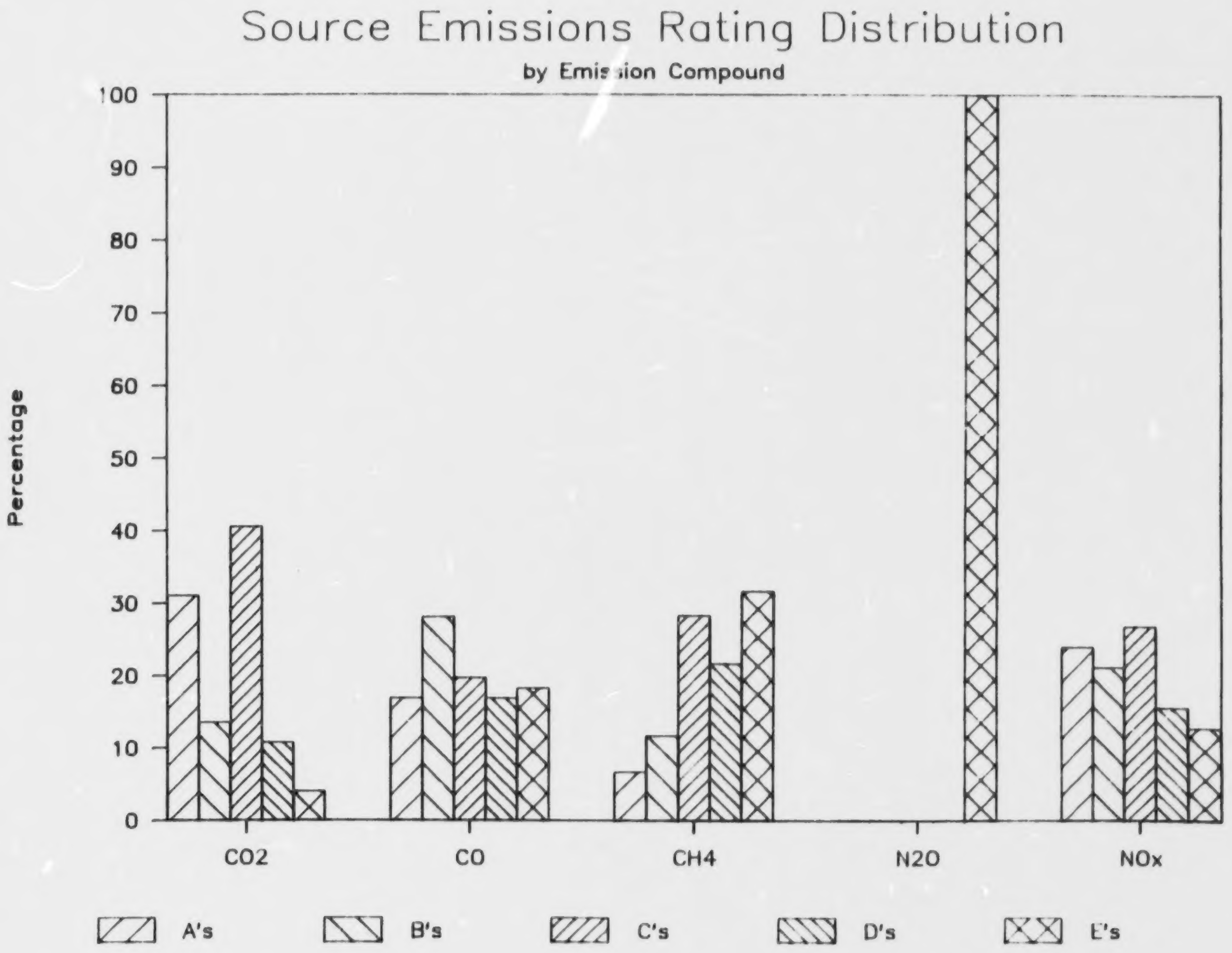

Figure 3. Distribution of emission factor ratings by gas.

carbonaceous species emitted by most combustion processes by several orders of magnitude; therefore, uncertainty associated with the emissions of CO, CH_4, or other carbonaceous species as gases or solids generally has a negligible impact on the CO_2 emission factor estimate and on the CO_2 emission factor rating.

Figure 4 shows the distribution of emission factor ratings for all gases for each source category. Overall, the source categories with the best emission factor ratings are also the most significant emission sources. Utility and industrial boiler sources have the best overall ratings. N_2O emission factors account for most of the "E" ratings for these two sources. NO_x and CO emission factors in these two categories generally have ratings of "A" and "B". Most of the transportation sources CH_4 and N_2O emission factors have a rating of "D" or lower. Kilns, ovens, and dryers noticeably have the lowest overall emission factor quality rating; only CO_2 emission factors have ratings as high as "B" and "C" in the kilns category. The emission factors for fuel production sources are also generally of lower quality than for other sources, with ratings of "C" and "D" evenly distributed for CO_2, NO_x, CO, and CH_4 emission factors.

The cost estimates are sensitive to the assumptions made regarding capacity factor when calculating annualized cost on an energy basis. Costs are also sensitive to the size of the facility being costed. When possible, reasonably representative source capacities were selected. However, in many cases, cost information was readily available for only a single source capacity. Costs vary considerably globally due to differences in labor costs, financing methods, inflation, taxes, and regulations from one country to another. The cost estimates should be regarded as rough estimates that indicate the relative cost of one technology to another.

The emission factor quality ratings identify some areas that could benefit from additional research. Many more test data are required before N_2O emission factors can be developed for any sources with good confidence. The applicability of U.S. data to develop globally representative emission

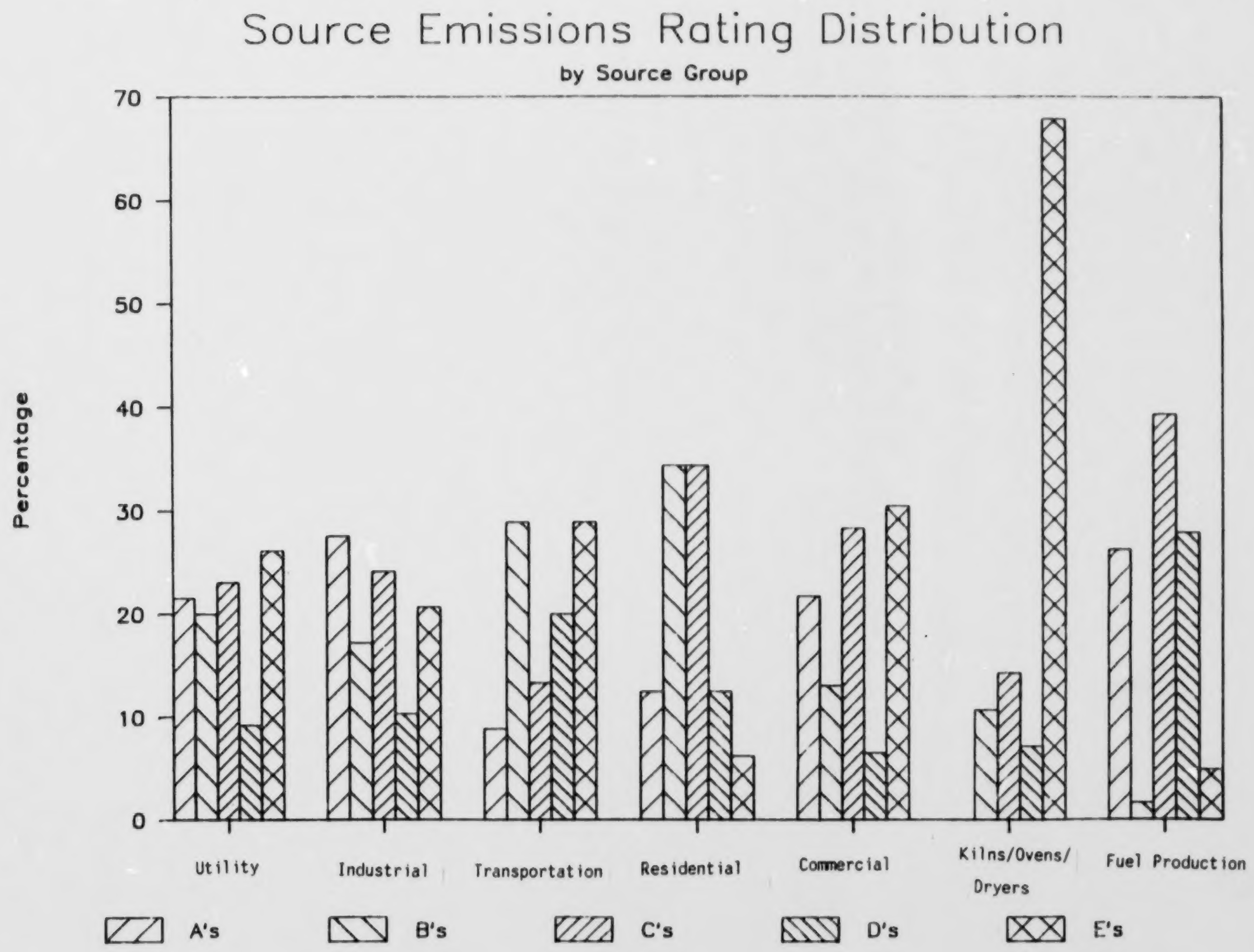

Figure 4. Distribution of emission factor ratings by source.

performance for emission sources from one region of the world to another would indicate that emission source parameters should be estimated independently for different regions of the world. Additional study, and possibly source testing, may be required to fill gaps in the emission database and to improve the quality of emission factors. The impact of control technologies on N_2O emissions requires more testing.

Specific tasks for further development of this database could include additional literature search, consultation with experts in the United States and internationally, and source testing, including the impact of control technologies on N_2O. Data from these activities could be used to improve the accuracy of current estimates, provide data where data is currently not included, and develop new emission source and control categories to account for regional differences in performance and cost.

SECTION 2

DATA REQUIREMENTS AND GENERAL TECHNICAL APPROACH

This section describes methods used to develop emission estimates and other data for globally significant anthropogenic sources of CO_2, CO, CH_4, NO_x, and N_2O. Where data were readily available, energy conversion efficiency, energy-based emission factors, control technology performance and cost, and source cost were estimated. Control technology performance parameters investigated include the efficiency penalty on the energy conversion process, the removal efficiency for each of the five gases, and the availability date of the technology.

Specifically, an emission factor quality rating scheme was developed to provide some insight into the accuracy of the emission factors. The rating criteria are described in this section, as are the control performance estimate and the method used to estimate costs for both emission sources and controls.

This section presents only a general discussion of the approaches commonly used to estimate emission and cost parameters. Additional details specific to each parameter are discussed in Sections 3 through 8.

EMISSION FACTOR ESTIMATES

The emission factors developed in this report represent the "uncontrolled" emissions from each source. The factors are usually presented on a mass of pollutant per unit energy basis. In some cases, the energy delivered to an end-user is used as the energy basis. The energy basis used within each source category is appropriately noted in the following sections. Many of the emission factors presented in this report were estimated from the Compilation of Air Pollutant Emission Factors, referred to throughout this report as AP-42 (U.S. EPA, 1985). The emission factors in AP-42 are generally reported on the basis of mass pollutant per unit mass of fuel consumed. The AP-42 mass-based basis emission factors were converted to an end-user energy basis, where appropriate using the fuel heating value and source energy conversion efficiency as follows:

$$EF = (\text{AP-42 EF}) \times \frac{1}{HV} \times \frac{1}{EFF} \qquad (1)$$

where:

EF = energy based emission factor (mass pollutant per unit energy output).

AP-42 EF = AP-42 emission factor (mass pollutant per unit input fuel mass or volume).

HV = fuel heating value (energy per unit fuel mass or volume).

EFF = energy conversion efficiency (fraction).

The calculation of an energy output-based emission factor requires that energy conversion efficiency be estimated. The calculation of either an energy output- or energy input-based emission factor from a mass basis factor both require the fuel heating value.

The next two subsections discuss energy conversion efficiency, fuel properties and energy basis emission factor development.

Energy Conversion Efficiency

Energy conversion efficiency is the ratio of energy output to energy input for an energy conversion technology. The input to energy conversion technologies included in this study is fuel energy. The output for a utility plant is electricity, which can be measured either at the busbar or after transmission and distribution. Utility efficiency data developed in this study are based on electricity delivered to end-users after transmission. For industrial boilers, the output is the incremental energy added to the boiler feed water for steam generation. For a kiln, oven, dryer, or process heater, the output is the thermal energy added to a material (e.g., for refinery process heaters it is the amount of energy added to the feedstock). Efficiencies were not developed for some emission sources because either energy conversion efficiency data were unavailable or it was more representative to develop emission factors on an energy input basis or a per pound of product basis.

The utility end-user energy conversion efficiency includes the multiplicative effects of boiler efficiency, thermal cycle efficiency, turbine-generator efficiency, and transmission losses. For both utility and industrial boiler sources, the factors that impact efficiency are the same; these factors include boiler design, fuel type, maintenance, operation, age, size, utilization, altitude, and the presence of pollution control equipment. Typically, boiler efficiency decreases with age, poor maintenance and operation, decreasing size, increasing altitude, low loads, and addition of pollution control equipment.

For most sources, data are not readily available from which to estimate globally representative energy conversion efficiencies. Exceptions include gas turbines, which are traded internationally, and utility sources, for which the United Nations compiles fuel use and electricity generation data. The United Nations data indicate that significant variations in the efficiency of utility plant energy conversion in different regions of the world. However, the United Nations data do not provide a breakdown of efficiency data for the boiler types included in this study. Because of the limited availability of this type of international efficiency data, efficiency estimates for most sources are based on data for U.S. emission sources.

In general, the efficiency estimates based on U.S. data are reasonably representative of the global average efficiency of new technology. Utility plants, for example, are built internationally primarily by U.S., Japanese, and European manufacturers and contractors, and generally have similar performance (Wilmoth, J., Combustion Engineering, Windsor, CT, personal communication, August 1987).

Estimates based on U.S. technology may not account for differences in efficiency due to technology already present in various regions of the world, which may have been poorly designed, built, operated, and maintained. However, an analysis of data for eight countries indicates that, over time, estimates applied globally based on U.S. efficiencies can be expected to reasonably approximate the energy conversion efficiencies of the most significant fuel consuming regions of the world.

Some technologies, such as industrial boilers, may be subject to more global variability than utility boilers because they can be procured domestically in many countries (Westsik, J., Bechtel Power Corporation, San Francisco, CA, personal communication, August 1987). However, most industrial regions of the world, which represent the largest fraction of fuel consumption and combustion-related emissions, are likely to have boiler efficiencies similar to those in the United States.

Although boiler efficiencies may be similar in the most significant fuel-consuming regions of the world, the efficiency of industrial fuel use per unit of delivered product does vary significantly from country to country. For example, in 1976 the United States used 21 million Btu to produce one ton of steel, whereas Germany used only 13 million Btu (Dean, 1980). The significant variations in industrial efficiency suggest that boiler efficiency is only one of many constraints on overall process efficiency, and that process fuel requirements per unit product manufactured are subject to global variation. However, because boilers are a significant emission source, and because of the variation of fuel requirements for industrial processes, only boiler energy requirements and emissions are included in this study.

The efficiency estimates developed for this work in general should be regarded as reasonable, nominal values for well-maintained and well-operated facilities. The energy conversion efficiencies are based on representative U.S. data.

Emission Factors

This section discusses the methods used to estimate emission factors for CO_2, CO, CH_4, NO_x, and N_2O. The sources of information for emissions of the five gases will be discussed briefly, followed by discussion of the need for fuel properties and efficiency to calculate energy based emission factors.

Emission factor estimates were derived based primarily on data available in various EPA documents. Typically, emission data for NO_x, CO, and CH_4 were available from AP-42, background information documents for New Source Performance Standards, environmental assessment studies for various sources, and from source test reports. No emission factors were available for N_2O, although limited test data were available for several sources. CO_2 emission factors were calculated from fuel properties and a carbon balance by assuming that, in many cases, all fuel carbon is transformed into CO_2, CO, and CH_4.

The emission factors developed in this study are for uncontrolled emission sources. To estimate a global emission inventory, additional data will be needed so that the global application of emission control technologies can be simulated. Emission reduction and energy efficiency penalty data for currently available and some advanced pollution control technologies were developed as part of this study but no attempt was made to define the use of these technologies around the world. The development of the control technology performance data will be discussed in more detail later in this section.

The fuel properties required for this study include heating value and weight percent of carbon in the fuel. The heating value is required to convert emission factors available in AP-42 and other sources from a mass of pollutant per mass fuel basis to a mass of pollutant per unit energy basis. The carbon content of the fuel is required to calculate CO_2 emissions.

Table 5 includes the nominal heating values and carbon contents used for 16 different fuels considered in this study. Heating values and carbon contents were selected based on representative U.S. values because detailed global data were not readily available. Actual heating values and carbon contents will vary from one region of the world to another for various fuels. For example, based on an analysis of data from the International Energy Agency (IEA) and lignite coal, average regional heating values vary from approximately 7,500 Btu/lb for the Organization for Economic Cooperation and Development (OECD) countries in Asia to nearly 10,900 Btu/lb for the continent of Africa (WCRR, 1983). A value of 10,000 Btu/lb was selected as representative of subbituminous/bituminous coals, which comprise roughly 65 percent of the world's accessible coal on a mass basis. The carbon content for coal of 65 percent is based on an average of many subbituminous/bituminous coals.

For utility and industrial boiler sources, emission factors were calculated on the basis of mass of pollutant per unit energy output. These calculations require both a fuel heating value and an energy conversion efficiency. The general equation for this calculation was presented earlier as Equation 1. For most other sources, emission factors are presented on a mass of pollutant per fuel energy input basis. These emission factors are typically calculated from a mass pollutant per mass (or volume) fuel emission factor from AP-42 using the general expression:

$$EF = (\text{AP-42 EF}) \times \frac{1}{HV} \qquad (2)$$

where:

EF = energy based emission factor (mass pollutant per unit energy input)

TABLE 5. FUEL PROPERTIES[a]

Fuel	Heating Value (MJ/kg)[b]	Carbon (wt percent)
GAS		
Butane/Propane	50.8	82.0
Coke Oven Gas	40.8	56.1
Methane (pure)	50.0	75.0
Natural Gas	51.1	70.6
Process Gas	54.0	70.6
LIQUID		
Crude Shale Oil	43.1	84.5
Diesel/Distillate	45.2	87.2
Gasoline	123 MJ/gal	85.7
Jet A	43.2	86.1
Methanol	59 MJ/gal	37.5
Residual Oil	43.0	85.6
SOLID		
Bagasse/Agric.	9.1	22.6
Charcoal	29.1	87.0
Coal	23.2	65.0
MSW	11.3	26.7
Wood	10.6	27.0

[a] Heating value and carbon content values are intended to be nominal, representative values. Actual fuel properties will vary.

[b] Unless otherwise indicated.

Sources: Babcock and Wilcox, 1978; Moscowitz, 1978; Perry and Chilton, 1973; Singer, 1981; UNEP, 1985; U.S. EPA, 1982a.

AP-42 EF = AP-42 emission factor (mass pollutant per unit input fuel mass or volume)

HV = fuel heating value (energy per unit fuel mass or volume)

For some fuel production sources, emissions are calculated based on a mass of pollutant per unit of crude oil produced, using typical fuel consumption per unit of crude oil produced for a specific technology (e.g., process heater).

The emission of CO_2 from a combustion source depends on the amount of carbon entering the process in the fuel and the amount of carbon leaving the process in various forms as part of the products of combustion. The carbon in the fuel is converted to CO, CO_2, CH_4, and other carbonaceous species that are exhausted as part of the flue gas. Carbon is not generally retained in ash formed during combustion (Singer, 1981). In most cases, the emission of CO_2 is orders of magnitude higher than that of any other carbonaceous species on a mass basis. The general expression used to calculate CO_2 emissions, including both CO and CH_4 in the carbon balance, is:

$$EFCO_2 = MWCO_2 \quad \frac{\%C}{HV} \times \frac{1}{MWC} - \frac{EFFCH_4}{MWCH_4} - \frac{EFCO}{MWCO} \qquad (3)$$

where:

$EFCO_2$ = CO_2 emission factor (g CO_2/GJ)

$MWCO_2$ = molecular weight of CO_2 (44 g/gmole)

%C = percent carbon in fuel, by weight (% fraction)

HV = fuel heating value (GJ/g)

MWC = molecular weight of carbon (12 g/gmole)

$EFCH_4$ = CH_4 emission factor (g CH_4/GJ)

$MWCH_4$ = molecular weight of CH_4 (16 g/gmole)

EFCO = CO emission factor (g CO/GJ)

MWCO = molecular weight of CO (28 g/gmole)

In some cases, additional carbon-containing compounds were included in the carbon balance. For example, methanol is emitted in significant quantities from methanol-fueled automobiles, and was included in the carbon balance. The

CO_2 emission factors presented in this report were calculated including both CO and CH_4 in the carbon balance, unless otherwise noted.

Nonmethane hydrocarbons were not included in the carbon balance. In some cases, particularly for transportation sources, the emission of nonmethane hydrocarbons is greater than that of methane, but the overall effect on the CO_2 emission factor of neglecting nonmethane hydrocarbons in the carbon balance is negligible because CO_2 emissions are always roughly two to three orders of magnitude greater than hydrocarbon emissions. In several cases, however, CO emissions represent a substantial fraction of the total CO and CO_2 emissions. For these reasons, the CO_2 emission factor, calculated based on a carbon balance including CO and CH_4, provides an accurate estimate of CO_2 emissions. The accuracy of the estimate is limited primarily by the quality of the fuel property data.

EMISSION FACTOR DATA QUALITY RATING

Because the emission factors developed for this study were derived from a variety of sources and generally required conversion from a mass to an energy basis using fuel properties, a rating scheme was developed to consistently characterize the quality of the emission factors. The rating scheme developed for this work is similar to rating schemes used in AP-42. Some additional considerations are included in the ratings because some of the emission factors were derived from sources other than AP-42 and because additional calculations were performed to estimate emission factors on an energy basis. First, considerations relevant to emission factors calculated based on AP-42 data will be discussed, followed by a discussion of quality rating considerations for factors derived from other sources. These discussions will be followed by a summary of the rating scheme.

In the cases where emission factors are based on data obtained from AP-42, the AP-42 emission factor quality rating, (generally "A" through "E," with "A" being the best) was adopted. These ratings were adjusted downward if, in the judgment of the engineering staff, the use of fuel property data to convert from a mass basis to an energy basis would degrade the quality of the emission factor. For the cases where emission factors were calculated on an energy output basis, the AP-42 rating was adjusted downward if the quality of the efficiency estimate was judged to reduce the quality of the emission factor. In no case was an AP-42 emission rating increased.

Data obtained from sources other than AP-42 were evaluated based on the quality and quantity of test data available from which to develop an emission factor. A large quantity of data, obtained by EPA approved test methods, with little scatter, would receive an initial rating of "A", but could be adjusted downward as for an AP-42 rating based on the quality of fuel or efficiency data used in calculating an energy basis emission factor. The ratings for factors other than AP-42 also were adjusted downward if significant variation in emissions could be expected in the emission source population due to variations in design, maintenance, and operation.

The primary and secondary considerations used in developing the emission factor quality ratings are summarized in Table 6. The primary considerations involve evaluating the source and quality of the emission data. For AP-42 derived factors, the AP-42 rating is converted directly to an "A" through "E" rating; for other data, an "A" through "E" rating is assigned based on the quantity and quality of the emissions data as discussed. The secondary considerations may result in reduction of the quality rating. The secondary considerations, regardless of the source of the emission data, include process variability, the quality of fuel properties used to convert to an energy basis, and the quality of the efficiency estimate used to convert to an energy output basis, where appropriate. Table 7 summarizes the guidelines for using the primary and secondary considerations to assign ratings for each emission factor. In some cases, emission factors may be assumed to be valid for more than one source due to similarities between sources and lack of emission data for one of the sources. A transfer of an emission factor from one technology to another will generally result in an "E" rating because of the lack of data for the source in question. An example is the use of data for residual oil-fired utility boilers to estimate emissions from shale oil-fired utility boilers. The rating for the CO_2 emission factors includes assessment of the impact on the CO_2 factor of possible variation in fuel properties, variation in emissions of CO and CH_4, and emissions of carbonaceous species not included in the carbon balance.

Because these ratings are qualitative, they indicate only the relative quality of the emission factors within this database and indicate areas that could benefit from additional research. The ratings presented for each factor

TABLE 6. RATING CONSIDERATIONS

Consideration	Description
PRIMARY CONSIDERATIONS FOR INITIAL RATING	
• Data from AP-42	Use AP-42 rating as an initial rating.
• Data from other sources	Evaluate quantity of data, test methods used, and data scatter to assign an initial rating.
• Data for CO_2 estimates	In addition to evaluating the quality of fuel property data, evaluate the impact of variation of emissions of all carbonaceous species on variation of CO_2 emissions.
SECONDARY CONSIDERATIONS	
• Process variability	Reduce initial rating if emissions are subject to significant variation due to variation in design or operation within a source population.
• Fuel properties	Reduce initial rating if significant variation can be expected in the fuel properties used to calculate emission factors, and/or fuel properties based on limited data.
• Efficiency	Reduce initial rating if efficiency estimate is subject to significant variation within a source population, and/or efficiency estimates based on limited data.
• Technology transfer	Use a low rating if emission factors for a given source are assumed the same as another source due to process similarities.

TABLE 7. QUALITY RATINGS[a]

Rating	Confidence	
	Primary Considerations[b]	Secondary Considerations[b]
A	High	High
B	High	Medium
C	Medium-High	Low-High
D	Medium	Medium
E	Low-Medium	High-Low

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[a] This table provides a general indication of the meaning of each rating, but does not represent strict guidelines.

[b] See Table 6.

reflect the professional judgment of the engineering staff; these ratings roughly indicate the accuracy with which the emission factors can be used to estimate emissions from a large number of sources.

EMISSION CONTROLS PERFORMANCE ESTIMATES

For each emission source technology, an attempt was made to identify emission control technologies that can be applied to reduce emissions of one or more of the five gases considered in this study. For a few sources, no control technologies could be readily identified, whereas for most sources, such as fossil fuel-fired utility plants, many control technologies could be identified. The performance parameters estimated for each control technology include the removal efficiency for each of the five gases, the emission source energy efficiency penalty associated with the energy requirements of the control technology, and the availability date for the control technology. Each of these parameters will be discussed separately in the following subsections.

Removal Efficiency

The removal efficiency for a given pollutant was determined from accepted values from the literature or from test data for technologies that are currently under development. In general, typical efficiencies from other EPA studies were used, where available. The removal efficiency is defined as follows:

$$\text{Removal Efficiency} = \frac{\text{Uncontrolled Emissions - Controlled Emissions}}{\text{Uncontrolled Emissions}} \qquad (4)$$

The removal efficiency may be either positive or negative. A positive removal efficiency indicates that the pollutant is reduced, whereas a negative removal efficiency indicates that the pollutant is increased. For example, automobiles equipped with catalytic emission controls generally have lower CO and NO_x emission rates than automobiles without emission control; however, CO_2 emissions increase because CO is catalytically converted to CO_2, resulting in a negative CO_2 removal efficiency. In many other cases, where CO emissions are a much smaller fraction of the total carbonaceous emissions for a source, a decrease in CO emissions may result in only a negligible increase in CO_2 emissions.

The removal efficiencies were selected to be representative of reasonable average maximum removal efficiencies. For example, selective catalytic reduction may be capable of 90 percent NO_x removal for sources burning very low sulfur fuels; however, 80 percent NO_x removal is a reasonable average removal efficiency for a larger range of fuel and operating conditions, and is therefore more representative of the global average emission reduction achievable with this particular technology.

Emission Source Efficiency Penalty

Most emission control technologies impact the overall efficiency of the emission source. Flue gas treatment systems, for example, create an additional pressure drop in the flue gas exhaust system, which must be overcome by an induced draft fan. The induced draft fan requires additional electricity. Other control technologies may modify the combustion conditions in a furnace, resulting in less than optimum combustion as a trade-off for reduced emission of a particular pollutant. Where data were readily available, these and other energy penalties due to control technologies were estimated in terms of a percent penalty on the emission source efficiency.

The efficiency penalty can be represented by the following equation:

$$\text{Percent Penalty} = \frac{\text{Uncontrolled Efficiency} - \text{Controlled Efficiency}}{\text{Uncontrolled Efficiency}} \qquad (5)$$

where "uncontrolled efficiency" is the efficiency of the emission source without emission control, and "controlled efficiency" is the efficiency of the emission source with the emission control technology. The efficiency penalty can be either positive or negative. A negative penalty indicates an improvement in source efficiency.

Availability Date

For each control technology, an availability date was estimated. The availability date indicates the first year in which a control technology was or may reasonable be expected to be commercially available. For existing commercially available technologies, the availability date is based on the first mention of application of the technology in the literature. The availability dates of advanced technologies currently under development are based on engineering judgment or, in some cases, on the date that the technologies are required due to emission regulations in the United States.

EMISSION SOURCE AND CONTROL COSTS

The basis for cost estimates for both emission sources and emission control technologies are discussed in this section, as are the internationally accepted constant dollar costing method. The data requirements for costs are discussed below. Finally, key sources of variation for the costing are discussed.

International Costing

The cost method of the International Union of Electricity Producers and Distributors (UNIPEDE) is widely accepted as a means for making meaningful international cost comparisons. Using a constant dollar approach, capital costs are levelized over the economic life of a facility by using the real escalation rate, which is simply the discount rate for borrowing money. The effects of inflation and taxes, which are specific to each country, are thereby excluded.

All costs are in 1985 constant dollars. The total annual cost includes the annual capital charge and the operating, maintenance, and fuel costs. For this study, fuel costs are excluded. The total annual costs developed using this method are independent of future inflation rates.

Cost Data Requirements

Costs are presented for utility and industrial boiler sources and for all control technology categories. The data requirements for the costing includes total capital cost, nonfuel annual costs, economic life, discount rate, facility size or capacity, and capacity factor. The annualized cost in constant dollars is converted to an energy basis by dividing the cost by the annual energy input for the source in question. For utility and industrial boiler sources, the costs are calculating on an energy output basis using the energy conversion efficiency discussed earlier. The general equation used to develop the cost estimates is:

$$\text{Cost (\$/J)} = \frac{CC\ (CRF)\ +\ AC}{CAP\ (CF)\ (8{,}760)\ (EFF)} \qquad (6)$$

where:

CC = capital cost (1985 dollars)

CRF = capital recovery factor

AC = annual non-fuel operating and maintenance costs (1985 dollars)

CAP = capacity (Joules/hr)

CF = capacity factor (fraction)

EFF = energy conversion efficiency (fraction)

The capital recovery factor is calculated from the equation:

$$CRF = \frac{i\ (1+i)n}{(1+i)^n - 1} \qquad (7)$$

where:

i = discount rate (decimal)

n = economic life (years)

From Equation 6, it is apparent that the levelized cost on an energy basis is sensitive to the choices made for capacity factor and source capacity. Capacity factor in general will affect the annual operating costs.

Variation in source capacity will change the levelized cost due to economy of scale effects. The levelized cost is also sensitive to the capital recovery factor. As seen in Equation 7, the assumptions regarding interest rate and economic life will determine the capital recovery factor.

Sources of Variation in Costing

The costs developed for this study are based on representative U.S. costs expressed in constant 1985 dollars. However, capital and operating costs for a specific plant, both within the United States, and to an even greater extent on a global scale, will be influenced by a number of factors, including:

- construction and operating labor costs (productivity, skill level, availability, wage rates),
- fuel quality (heating value, ash content for coal),
- site conditions (congestion, terrain, altitude, climate),
- plant capacity factor,
- financing costs (financing method, inflation, interest rates, length of construction), and
- regulatory policies (environmental and utility commission policies).

A comparison of capital costs for coal-fired utility plants constructed in industrialized countries (United States, western Europe, and Japan) revealed variations of up to 50 percent, due in part perhaps to variations in currency exchange rates (Verbeek and Gregory, 1986). For utility sources, plant capacity factor varies significantly for fossil fuel-fired plants from 28 percent in South America to 59 percent in the USSR (United Nations, 1986).

The costs presented in this report are intended as indicative of the relative costs of various technologies. Actual costs may vary significantly from these values for a given facility due to site specific and regional variations in construction costs, labor, financing, and regulations. Therefore, these costs should be viewed as only approximately representative of global cost estimates, and as such, great care should be taken in qualifying any conclusions reached as a result of the use of these cost estimates.

SECTION 3
UTILITY SOURCES AND CONTROLS

As part of the utility category, performance and costs estimates were developed for 15 utility plant technologies and for 9 emission control technologies. The source and control technologies primarily include conventional, commercially available technologies. The first part of this section discusses the development of efficiency, emission factor, and cost estimates for utility sources. A discussion of efficiency penalty, emission reduction efficiency, and costs for utility emission control technologies follows. A glossary of all abbreviated terms appearing in the tables of this section appears at the end of this report.

DATA FOR EMISSION SOURCES

Table 8 summarizes the efficiency, emission factor, and cost estimates developed for 15 utility plant technologies. These include natural gas, distillate oil, residual oil, shale oil, coal, wood, and municipal solid waste (MSW) combustion technologies. The efficiency for each technology is based on the conversion of fuel energy to electricity delivered to the user. Costs are 1985 annualized costs based on the total electricity delivered to the user over a period of 1 year. Uncontrolled emission factor estimates are reported on the basis of grams of pollutant emitted per gigajoule of electricity delivered to the user. To the right of each emission factor is the emission factor quality rating. For each utility technology, appropriate control technologies are identified by codes. The codes within parenthesis are retrofit options.

Efficiency and Transmission Loss

The utility plant efficiency estimates reported in Table 8 represent the conversion of fuel energy to electricity delivered to end-users through a transmission and distribution system. Typically, power plant electrical generation is measured at the busbar, which approximately represents the boundary between the power plant and the electrical distribution system. Additional losses in transformers, transmission wires, and other equipment are

TABLE 8. UTILITY BOILER SOURCE PERFORMANCE AND COSTS

Source	Efficiency (%)	Cost[a] ($/J end-use)	Emissions Factors (g/GJ delivered electricity) and Data Quality Ratings (A - E)					Controls[b]
			CO_2	CO	CH_4	N_2O	NO_x	
Natural Gas - Boilers	32.4	6.4E-09	150,000 A	53 A	0.4 C	N/A	740 A	U1, U3, U8, U10, U13, U18, (U19, U21, U25, U26, U27)
Gas Turbine Combined Cycle	42.0	4.3E-09	120,300 A	70 A	13 C	N/A	400 A	U14, U15
Gas Turbine Simple Cycle	26.4	1.0E-09	191,400 A	110 A	20 C	N/A	640 A	U14, U15
Residual Oil Boilers	32.4	6.7E-09	230,000 A	43 A	2.2 A	N/A	590 A	U1, U4, U7, U10, U12, U17, (U19, U22, U24, U26, U27)
Distillate Oil Boilers	32.4	6.7E-09	220,000 A	43 D	0.1 D	N/A	200 D	U1, U4, U7, U10, U12, U17, (U19, U22, U24, U26, U27)
Shale Oil Boilers	32.4	6.7E-09	230,000 E	43 E	2.2 E	N/A	590 E	U1, U4, U7, U10, U12, U17, (U19, U22, U24, U26, U27)
MSW - Mass Feed	18.7	3.8E-08	460,000 D	500 B	N/A	N/A	710 B	U1
MSW - Refuse Derived Fuel	18.7	3.8E-08	450,000 D	N/A	N/A	N/A	N/A	U1

TABLE 8. (Continued)

Source	Efficiency (%)	Cost[a] ($/J end-use)	Emissions Factors (g/GJ delivered electricity) and Data Quality Ratings (A - E)					Controls[b]
			CO_2	CO	CH_4	N_2O	NO_x	
Coal-Spreader Stoker	31.0	N/A	340,000 C	370 B	2.1 B	2.5 E	1,000 B	U1, U2, U10, U11, U16, (U19, U20, U27)
Coal-Fluidized Bed Combined Cycle	35.0	1.2E-08	290,000 C	N/A	1.8 C	N/A	N/A	U10, U12, U16, (U27)
Coal-Fluidized Bed	31.4	9.5E-09	330,000 C	N/A	2.0 C	N/A	770 C	U10, U12, U16, (U27)
Coal - Pulverized Coal	31.3	9.5E-09	330,000 C	42 B	2.0 B	2.5 E	2,600 C	U9, U10, U11, U16, (U27)
Coal-Tangentially Fired	31.3	9.5E-09	330,000 C	42 B	2.0 B	2.5 E	1,000 B	U1, U2, U6, U10, U11, U16, (U19, U20, U23, U26, U27)
Coal - Pulverized Coal Wall-Fired	31.3	9.5E-09	330,000 C	42 B	2.0 B	2.5 E	1,400 B	U1, U2, U5, U10, U11, U16, (U19, U20, U23, U26, U27)
Wood-Fired Boilers	15.9	1.3E-08	590,000 C	8,800 D	88 E	N/A	670 C	U1, U10, U11, (U19, U27)

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[a] All costs in 1985 dollars.

[b] Control codes in parenthesis indicate the retrofit emission control options. The controls are defined ibn Table 11.

incurred in the distribution of electricity from the power plant to the end-users.

To estimate the end-user energy conversion efficiency, first the busbar efficiency was estimated; the busbar efficiency for each source was then reduced to account for typical transmission losses using a global average transmission loss. The development of busbar efficiency estimates will be discussed separately for each emission source. The development of the transmission loss estimate, which was applied to all utility sources, will be discussed first.

The global average transmission loss as a percent of busbar generation was determined by ranking the largest electricity generating nations and their transmission losses. From this information, a generation-weighted transmission loss was derived. Table 9 presents the top 11 electricity generating countries, which represent nearly 75 percent of the world's total generation. The rankings in Table 9 are based on U.N. data. The weighted average loss is 8 percent. Therefore, a transmission efficiency of 92 percent was applied to all busbar efficiencies to determine the net efficiency of electricity production and distribution.

The efficiency estimates for natural gas-, distillate oil-, residual oil-, and shale oil-fired boilers are all 32.4 percent conversion of fuel energy to end-user electricity. The efficiency for these four fuels is estimated to be the same because typically natural gas-fired and oil-fired boilers have the same thermal efficiency. Boiler efficiency is estimated to be 88 percent, based on 85 percent efficiency for a boiler without air preheat and an additional 3 percentage points due to air preheat (U.S. EPA, 1982a; Babcock and Wilcox, 1978). The boiler efficiency is limited by the combustion efficiency, heat transfer losses within the boiler, and losses due to energy exhausted in flue gas. The overall power plant efficiency is limited by the boiler efficiency and by other factors. These factors include cycle losses and auxiliary equipment. The cycle efficiency is limited by the maximum theoretical efficiency for any heat engine. Additional losses in an actual power plant cycle are introduced by inefficiencies in the turbine. Energy is required to operate power plant auxiliary machinery such as fans and pumps, which reduce the energy available for transmission. The busbar efficiency for these four sources, after accounting for boiler efficiency, cycle efficiency, and auxiliary power requirements, is 35.2 percent.

TABLE 9. GLOBAL AVERAGE TRANSMISSION LOSS

Country	Percent of World Total Generation[a]	Percent Weight	Percent Loss[b]
United States of America	26.7	36	7.0
Union of Soviet Socialtist Republic	16.1	22	8.3
Japan	7.0	9	6.1
Canada	4.7	6	8.5
People's Republic of China	4.1	6	14.6
Federal Republic of Germany	4.1	6	4.3
France	3.3	4	7.5
United Kingdom	3.0	4	8.1
Italy	1.9	3	8.8
Brazil	1.9	3	8.3
India	1.8	2	18.0
TOTAL	74.6	100	AVE = 8.0[c]

[a] Includes fossil fuel, hydroelectric, and nuclear generation.

[b] Percent of busbar generation lost in transmission and distribution.

[c] Weighted average based on electrical generation.

Source: United Nations, 1986.

A globally representative simple cycle gas turbine efficiency was estimated based on projected international sales data for several gas turbine models and a sales-weighted average of their respective efficiencies. Gas turbine models with the highest projected sales included most General Electric models, the Westinghouse 251 and 501, and models from Brown Boveri, Rolls Royce, Avco, and Solar. The average efficiency for a simple cycle gas turbine, including a transmission loss of 8 percent, is 26.4 percent. As a check, this efficiency was compared to the 1985 U.S. national efficiency, adjusted for transmission loss, of 26.2 percent, indicating that the estimate derived from a global sales-weighted average is reasonable.

Busbar efficiencies for combined cycle gas turbines range from roughly 43 percent to 50 percent (Cohen et al., 1987). Assuming a representative efficiency approximately in the middle of this range, an end-user energy conversion efficiency of 42 percent was derived.

The efficiencies for coal boilers were estimated in a manner similar to those for oil and gas boilers. For spreader stoker coal boilers, a boiler efficiency of 81 percent was adjusted to 84 percent to account for air preheat (Babcock and Wilcox, 1978). The utility boiler efficiency for pulverized coal (PC) boilers, including cyclone, tangentially fired (TF), and wall-fired (WF) units, is approximately 85 percent, including air preheat (Holstein, 1981). From these boiler efficiencies, and from cycle losses and the typical energy requirements for power plant auxiliaries as previously discussed, the busbar efficiency was estimated to be 33.7 percent for spreader stoker units and 34.0 percent for the pulverized coal units. These values are equivalent to an end-user energy conversion efficiencies of 31.0 percent and 31.3 percent, respectively.

The busbar efficiency of coal-fired fluidized bed (FB) and fluidized bed combined cycle (FBCC) plants are 34.1 percent and 38.0 percent, respectively. The corresponding end-user energy conversion efficiencies, including transmission loss, are 31.4 percent and 35.0 percent, respectively. The busbar efficiency of municipal solid waste (MSW) mass feed-fired utility plants is approximately 20.3 percent (EPRI, 1986). This efficiency, adjusted for transmission loss, is 18.7 percent. No data were readily available for MSW refuse derived fuel (RDF)-fired utility plants; the efficiency of the mass feed unit was assumed to be representative of the efficiency of a RDF unit. A typical efficiency for wood-fired utility plants is 17.3 percent at the busbar, adjusted to 15.9 percent at the end-user (EPRI, 1986).

Emission Factors

For many emission sources, the emission factors for NO_x, CO, and CH_4 are based on AP-42 emission factors converted to an energy output basis using the appropriate fuel property data from Table 5 and the end-use energy conversion efficiency from Table 8. The emissions sources for which AP-42 factors were available for NO_x, CO, and CH_4 include natural gas, residual oil, distillate oil, coal spreader stoker, pulverized coal cyclone, pulverized coal tangential fired, and pulverized coal wall-fired boilers. The NO_x, CO, and CH_4 emission factors for other sources will be discussed in more detail. Because emissions of CO and CH_4 for utility sources are generally negligible on a mass basis compared to CO_2, the CO_2 emission factor was calculated only from the fuel properties. The exception to this includes wood-fired boilers, for which CO emissions were included in the carbon balance, and gas turbines, for which both CO and CH_4 were included.

The emission factors for N_2O are estimated based on limited test data for sources or fuels for which test data were available. Recent measurements have shown that most of the existing N_2O data were collected with procedures that allow formation of N_2O in sample containers awaiting analysis. Only those measurements made with new procedures can be considered reliable at this time. Consequently, the N_2O data base is very small, consisting of measurements at less than a dozen coal-fired power plants (Montgomery et al., 1989).

The emission factors for NO_x and CO for natural gas-fired utility gas turbines were available on an energy input basis (Shih et al., 1979). Although the emission characteristics of simple cycle and combined cycle gas turbines are the same on an energy input basis, they differ on an energy output basis because of differences in efficiency. The emission factors for NO_x and CO were converted to an energy output basis using the gas turbine efficiencies in Table 8. An emission factor for CH_4 was available and was converted from a mass to an energy basis using the heating value of natural gas from Table 5 and the end-use efficiencies for gas turbines (Touchton et al., 1982). The CO_2 emission factors for gas turbines were calculated including both CO and CH_4 in the carbon balance. N_2O emissions were estimated as approximately 5 percent of NO_x emissions, based on tests for natural gas-fired sources.

Although no emission factors for utility distillate oil-fired sources were available in AP-42, distillate oil utility emissions were estimated based on the ratio of distillate oil industrial boiler emissions to residual oil industrial boiler emissions multiplied by the residual oil utility boiler emissions for NO_x and CH_4. For CO, the emission factor was assumed to be the same as for residual oil utility boilers since the AP-42 CO emission factors for industrial and commercial residual and distillate oil boilers are all the same. No emission factors were readily available for shale oil-fired boilers. The emissions of shale oil boilers were assumed to be the same as those for residual oil-fired boilers because of similarities in the fuel properties of both oil types.

For MSW mass burn boilers, the CO emission factor is based on 11 test measurements from sources in the United States, Japan, Germany, Sweden, and Canada (Young et al., 1979). The NO_x emission factor is based on data for industrial mass burn facilities. No data were readily available for CH_4 or N_2O emissions for MSW boilers. No emissions data was available for MSW RDF-fired boilers.

For fluidized bed boiler utility plants, the NO_x emission factor is based on test data (U.S. EPA, 1982b). CH_4 emissions are assumed to be the same as for other types of coal-fired boilers because AP-42 CH_4 emission factors for all types of coal-fired utility boilers except underfeed stokers are the same. No data were readily available for CO emissions from fluidized bed boilers. The emission rate of N_2O is assumed to be roughly 25 percent of that for NO_x, although it is likely that, because fluidized bed boilers typically operate at lower temperatures than other boiler types, N_2O emission could differ substantially from this estimate. For fluidized bed combined cycle utility plants, no emission factors were readily available. However, the CH_4 emission factor was calculated by assuming that the emissions on a mass bass are the same as for other coal boilers, and the CO_2 emission factor was calculated by carbon mass balance.

For wood-fired boilers, emission factors for industrial boilers from AP-42 were used to calculate the end-use energy-based emission factors for NO_x, CO, and CH_4.

Cost

The basis for the costs in Table 8 is summarized in Table 10. These costs are only approximately representative of global average costs, and, as noted in Section 2, great care should be exercised in qualifying any conclusions reached using these estimates. Table 10 presents the capacity, total capital cost, annual costs, and economic life assumed in calculating the levelized annual cost. For all utility sources, a capacity factor of 0.45 was used, based on the average global utilization of installed electricity generating capacity from U.N. statistics (United Nations, 1986). Representative average source capacities were selected as the basis for the cost estimates. However, in cases where costs were not available for an average size plant, the cost estimates are based on a plant capacity for which costs were readily available. The costs were converted to an end-user energy basis using transmission efficiency for those costs that were available on a busbar basis. All costs are in 1985 dollars and were annualized in constant dollars in Table 8 using a discount rate of 5 percent and the economic life indicated in the table.

UTILITY SOURCE EMISSION CONTROL TECHNOLOGIES

Emission control technologies for utility plants and their performance and cost parameter estimates are summarized in Table 11. Table 11 includes the control technology codes corresponding to Table 8. Table 11 also includes the efficiency penalty due to each control technology, the levelized cost in constant dollars on an end-use energy basis, the emission reduction for each pollutant, and the estimated availability date.

Nine distinct control technologies are included in Table 11. One of the technologies is an advanced technology for removing CO_2 from the utility plant flue gas using an adsorption/regeneration technique and disposal of the CO_2 by injection into evacuated salt mines or into the ocean. Although this technology is not commercially proven, it is included to provide an option for CO_2 control. Of course, another option for reducing CO_2 emission on an energy output basis is improvement of the energy conversion efficiency associated with the emission source. Although only nine technologies were evaluated for utility emission controls, in many cases the performance or cost of these

TABLE 10. UTILITY PLANT COSTS[a]

Source	Capacity (MW)	Capital Cost ($ 10^6)	Annual Cost ($ 10^6)	Reference	Life (years)
Natural Gas Boiler	300	320	4.4	17	30
Gas Turbine Combined Cycle	220	150	2.9	8	30
Gas Turbine Simple Cycle	75	30	0.3	8	30
Residual Oil Boiler	300	340	4.4	17	30
Distillate Oil Boiler[b]	300	340	4.4	--	30
Shale Oil Boiler[b]	300	340	4.4	--	30
MSW - Mass Feed	45	200	6.2	8	20
MSW - RDF	45	200	6.2	8	20
Coal - FBCC	500	780	34	8	40
Coal - FB	500	660	23	8	40
Coal - Cyclone[c]	300	410	9.2	17	30
Coal - TF[c]	300	410	9.2	--	30
Coal - WF[c]	300	410	9.2	--	30
Wood	24	49	1.0	8	30

[a] All costs in 1985 dollars.
[b] Assumed same costs as for residual oil-fired boilers.
[c] The costs for all PC boilers are assumed to be the same.

Source: Holstein, 1981.

TABLE 11. UTILITY EMISSION CONTROLS PERFORMANCE AND COSTS

Technology	Code	Efficiency[a] Loss (%)	Cost[b] ($/J End-Use)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
Low Excess Air	U1	-0.5	2.4E-12	Negligible	Negligible	Negligible	N/A	15	1970
Overfire Air - Coal	U2	0.5	7.5E-12	Negligible	Negligible	Negligible	N/A	25	1970
Overfire Air - Gas	U3	1.25	7.5E-12	Negligible	Negligible	Negligible	N/A	40	1970
Overfire Air - Oil	U4	0.5	7.5E-12	Negligible	Negligible	Negligible	N/A	30	1970
Low NO_x Burner - Coal	U5	0.25	2.2E-11	Negligible	Negligible	Negligible	N/A	35	1980
Low NO_x Burner - TF	U6	0.25	6.7E-11	Negligible	Negligible	Negligible	N/A	35	1980
Low NO_x Burner - Oil	U7	0.25	2.1E-11	Negligible	Negligible	Negligible	N/A	35	1980
Low NO_x Burner - Gas	U8	0.25	2.1E-11	Negligible	Negligible	Negligible	N/A	50	1980
Cyclone Combustion Modification	U9	0.5	1.6E-10	N/A	N/A	N/A	N/A	40	1990
Ammonia Injection	U10	0.5	5.5E-10	Negligible	Negligible	Negligible	N/A	60	1985
SCR[c] - Coal	U11	1	1.5E-09	Negligible	8	Negligible	N/A	80	1985
SCR - Oil, AFBC	U12	1	1.1E-09	Negligible	8	Negligible	N/A	80	1985
SCR - Gas	U13	1	7.1E-10	Negligible	8	Negligible	60	80	1985
Water Injection - Gas Turbine Simple Cycle	U14	1	1.4E-10	Negligible	Negligible	Negligible	N/A	70	1975

TABLE 11. (Continued)

Technology	Code	Efficiency[a] Loss (%)	Cost[b] ($/J End-Use)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
SCR - Gas Turbine	U15	1	2.0E-09	Negligible	8	Negligible	60	80	1985
CO_2 Scrubbing - Coal	U16	22.5	5.0E-09	90	N/A	N/A	N/A	N/A	2000
CO_2 Scrubbing - Oil	U17	16.0	5.0E-09	90	N/A	N/A	N/A	N/A	2000
CO_2 Scrubbing - Gas	U18	11.3	5.0E-09	90	N/A	N/A	N/A	N/A	2000
Retrofit LEA	U19	-0.5	3.2E-12	Negligible	Negligible	Negligible	N/A	15	1970
Retrofit OFA - Coal	U20	0.5	7.2E-12	Negligible	Negligible	Negligible	N/A	25	1970
Retrofit OFA - Gas	U21	1.25	7.2E-12	Negligible	Negligible	Negligible	N/A	40	1970
Retrofit OFA - Oil	U22	0.5	7.2E-12	Negligible	Negligible	Negligible	N/A	30	1970
Retrofit LNB - Coal	U23	0.25	2.4E-11	Negligible	Negligible	Negligible	N/A	35	1980
Retrofit LNB - Oil	U24	0.25	5.4E-11	Negligible	Negligible	Negligible	N/A	35	1980
Retrofit LNB - Gas	U25	0.25	5.4E-11	Negligible	Negligible	Negligible	N/A	50	1980
Burners Out of Service (BOOS)	U26	0.5	0	Negligible	Negligible	Negligible	N/A	30	1975
Retrofit SCR[c]	U27								

[a] Efficiency loss as a percent of end-user energy conversion efficiency. Negative loss indicates an efficiency improvement.

[b] All costs in 1985 dollars.

[c] SCR = Selective catalytic reduction.

[d] Retrofit SCR performance may be assumed to be the same as for a new SCR systems, but cost is a factor of 1.5 greater.

N/A = not available.

technologies varies depending on the source to which they are applied. Costs for several of the technologies were also evaluated on a retrofit basis.

Efficiency penalties, emission reduction efficiencies, and costs are discussed below.

Efficiency Penalties

The efficiency penalties for most technologies were taken directly from the literature. It should be emphasized that the efficiency penalties are nominal values and are likely to vary from one application to another. The penalties for low excess air, overfire air, low NO_x burners, and ammonia injection are based on the efficiency penalty to an industrial boiler since utility data were not readily available (Kim et al., 1979).

Little detail was available for cyclone staged combustion modifications (Thompson et al., 1987). An efficiency penalty of 0.5 percent was assumed as a rough estimate.

The efficiency penalty for selective catalytic reduction (SCR) is based on an estimated increase in utility plant heat rate of roughly 0.8 percent (Bauer and Spendle, 1984). A nominal value of 1 percent penalty is assumed.

The efficiency penalty for gas turbine water injection is a function of the water injection rate. For the control level considered, a 1 percent efficiency penalty was selected as representative based on the required water injection rate (U.S. EPA, 1987).

The efficiency penalties for the CO_2 scrubber are substantial and vary depending on the fuel burned. The CO_2 scrubbing system results in a significant penalty on the thermal cycle of the power plant because steam is required for CO_2 regeneration; thermal energy is needed to remove CO_2 from the solvent on which it is absorbed from the flue gas. In addition, electricity is required to liquefy the CO_2 and to transport it via pipeline to its ultimate disposal site. The electricity requirement for the liquefaction and disposal depends only on the quantity of CO_2 requiring disposal. The quantity is higher for coal on an energy basis because coal has a higher ratio of carbon per unit heating value than does oil, and both oil and coal have a higher ratio of carbon to unit heating value than does natural gas. Therefore, the energy penalty for CO_2 removal at a coal-fired power plant is higher than that for a natural gas-fired plant due to the different properties of the two fuels (Steinberg et al., 1984).

Removal Efficiencies

The removal efficiencies for low excess air, overfire air, and low NO_x burners are based on a review of several references. These technologies generally impact only NO_x emissions. Average maximum removal efficiencies were selected; the efficiencies vary for overfire air and low NO_x burners as a function of the fuel fired. If operated properly, these technologies generally do not significantly impact the emissions of CO, CH_4, and CO_2. No data were readily available for N_2O.

Little information was readily available on the NO_x removal efficiency of cyclone furnace combustion modifications since it is a relatively new technology, and no data were readily available on the impact of cyclone combustion modifications on other species. However, a nominal value of 40 percent NO_x reduction is reported (Thompson et al., 1987).

On the average, ammonia injection is capable of 60 percent NO_x removal. No significant impact on the emissions of the other compounds is reported (Kim et al., 1979).

SCR can reduce emissions of N_2O, based on a test of a natural gas-fired internal combustion engine. No data were available regarding the effect of SCR on N_2O in the flue gas of coal- or oil-fired sources. SCR also reduces CO by a small percentage,but is primarily most effective in reducing NO_x by about 80 percent (Castaldini and Waterland, 1986).

Gas turbine water injection is capable of over 70 percent NO_x reduction. Although water injection can impact the emissions of CO and CH_4 to some extent in specific applications, on the average, the impact is negligible. The impact on CO_2 emissions is likely to be negligible in any case (U.S. EPA, 1977a).

No data is available on the impact of the advanced concept CO_2 scrubbing system on pollutants other than CO_2, for which the design removal efficiency is 90 percent (Steinberg et al., 1984).

Burners out of service (BOOS) is a retrofit control option which can be applied to wall-fired or tangentially fired boilers and is capable of about 30 percent NO_x removal for coal, oil, or natural gas (Kim et al., 1979).

Cost

The basis for the annualized control technology costs in Table 11 is presented in Table 12. Table 12 lists the emission source capacity, and the control technology capital cost and nonfuel annual costs. All costs are in 1985 dollars, and the costs in Table 11 were levelized based on a capacity factor of 0.45, an economic life of 30 years, and an interest rate of 5 percent. The factors used to calculate retrofit costs based on the costs for new controls are included in the table.

Because in some cases costs were available only for a control technology applied to sources of arbitrary capacities, it was not always possible to develop control costs using the same source capacity as for the source costs. Although the capacities of some sources and controls used for costing do not match, developing costs on a consistent capacity basis would have required effort beyond the scope of this project, and would have required additional assumptions in many cases.

TABLE 12. UTILITY EMISSION CONTROL COSTS[a]

Technology	Source Category	Capital Cost ($1,000)	Annual Cost ($1,000)
Low Excess Air (LEA)	2500 x 10^6 Btu/hr input	67	3
Overfire Air (OFA)	500 MW output	460	23
Low NO_x Burner (LNB)	500 MW output	1,400	69
LNB - Tangential Firing[b]	500 MW output	4,100	210
Cyclone Combustion Modification	-	$20/KW	$1/KW/yr
Ammonia Injection	200 x 10^6 Btu/hr input	350	120
SCR - Coal[c]	300 MW output	26,000	4,500
SCR - Oil, FBC[c]	300 MW output	22,000	3,400
SCR - Gas[c]	300 MW output	18,000	1,900
Water Injection - Gas Turbine (Simple Cycle)	400 x 10^6 Btu/hr input	710	14
SCR - Gas Turbine	400 x 10^6 Btu/hr input	3,300	680
CO_2 Scrubber	-	$673/KW	$45/KW/yr
Retrofit LEA	Ratio of retrofit to new cost is 1.32		
Retrofit OFA	Ratio of retrofit to new cost is 1.64		
Retrofit LNB	Ratio of retrofit to new cost is 1.54		
Retrofit SCR	Ratio of retrofit to new cost is 1.5		

[a] All costs in 1985 dollars.

[b] Assumed cost for low NO_x burners applied to tangentially fired furnaces to be three times the cost for other low NO_x burners as an order-of-magnitude estimate.

[c] SCR costs calculated from an algorithm based on Bauer and Spendle, 1984.

Sources: Steinberg et al., 1984; U.S. EPA, 1977a.

SECTION 4
INDUSTRIAL BOILER SOURCES AND CONTROLS

Performance and cost estimates were developed for seven industrial boiler types and six industrial boiler emission control technologies. All of the boilers and controls represent currently available technologies. This section discusses source performance and cost estimates, as well as emission control performance and cost estimates.

SOURCES

Table 13 summarizes the efficiency, cost, and emission factor estimates developed for industrial boilers. Estimates were developed for sources burning coal, residual oil, distillate oil, natural gas, wood, bagasse and agricultural waste, and MSW. The efficiency is based on the conversion of fuel energy to thermal energy for water to steam generation. The costs are based on the annual energy delivered in generating steam. The emission factors are reported on the basis of grams of pollutant emitted per gigajoule of energy delivered to a steam user. The energy delivered to a steam user is the difference between the thermal energy contained in the steam leaving the industrial boiler and the thermal energy in the condensate water returning from the user back to the boiler. To the right of each emission factor is the corresponding quality rating. For each industrial boiler technology, the appropriate control technologies are identified by codes.

Efficiency

The efficiency estimates in Table 13 represent the conversion of fuel energy to the energy delivered to a steam user. The estimates are based on information from NSPS background information documents for industrial boilers (U.S. EPA, 1982a,b).

Most coal-fired industrial boilers in the United States are watertube boilers. These may be pulverized coal or stoker designs. The efficiency of coal-fired industrial boilers ranges from about 78 percent for underfeed stokers to about 82 percent for pulverized coal-fired boilers. A value of 80 percent was selected as representative of coal-fired industrial boilers. Oil

TABLE 13. INDUSTRIAL BOILER SOURCE PERFORMANCE AND COST

Source	Efficiency (%)	Cost[a] ($/J end-use)	Emissions Factors (g/GJ delivered steam) and Data Quality Ratings (A - E)					Controls[b]
			CO_2	CO	CH_4	N_2O	NO_x	
Coal-Fired Boilers[d]	80	3.6E-09	130,000 C	110 B	2.9 B	N/A E	390 B	I1, I2, I5, I9, I10, (I13, I14, I17, I20)
Residual Oil-Fired Boiler	85	1.4E-09	88,000 A	17 A	3.3 A	N/A E	180 A	I1, I4, I6, I8, I9, I11, (I13, I16, I18, I20)
Natural Gas-Fired	85	1.4E-09	57,000 A	18 A	1.5 C	N/A E	71 A	I1, I3, I7, I8, I9, I12, (I13, I15, I19, I20)
Wood-Fired Boilers	68	6.3E-09	140,000 C	2,100 D	21 E	N/A E	160 C	I1, I9, I10, (I14)
Bagasse/Agricultural Waste-Fired Boilers	60	N/A	150,000 A	2,700 E	N/A	N/A	140 C	I1
MSW - Mass burn	70	N/A	120,000 D	130 B	N/A	N/A	190 C	I1
MSW - Small modular	55	N/A	160,000 D	32 B	N/A	N/A	240 C	I1

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[a] All costs in 1985 dollars.

[b] Control codes in parenthesis indicate retrofit emission control options. The controls are defined in Table 15.

fired and natural gas-fired watertube boilers generally have similar efficiencies of roughly 85 percent (U.S. EPA, 1982a).

Spreader stoker designs are the most common for boilers firing wood waste and typically have efficiencies of 65 to 70 percent. A value of 68 percent was selected as representative. Spreader stoker boilers firing bagasse are roughly 60 percent efficient. MSW mass feed boilers have an efficiency of 70 percent, whereas MSW small modular boilers have an efficiency of 55 percent (U.S. EPA, 1982b).

Emission Factors

No N_2O emission factors for industrial boilers have been provided since all existing test data have recently been shown to be inaccurate.

For coal-fired industrial boilers, emission factors for NO_x, CO, and CH_4 were estimated from AP-42 emission factors for pulverized coal, spreader stoker, overfeed stoker, and underfeed stoker industrial boilers. The emission factors for these four boiler types were averaged for each of the three pollutants based on the percent of the total U.S. coal-fired boiler capacity represented by each source. Using a boiler population weighted average approach, it is possible to represent the emissions of different coal-fired boiler types with a single set of emission factors. Pulverized coal boilers comprised roughly 37 percent of the total based on capacity, whereas spreader stoker, underfeed stoker, and overfeed stoker comprised 26 percent, 27 percent, and 10 percent of the total, respectively (U.S. EPA, 1982a). The weighted average emission factors were converted from a mass to an input energy basis using the coal heating value from Table 5 and then to an output energy basis using the boiler efficiency from Table 13.

The NO_x, CO, and CH_4 emission factors for residual oil-, natural gas-, and wood-fired boilers were taken from AP-42 and converted to an output energy basis using the appropriate fuel heating values and boiler efficiencies.

For bagasse-fired boilers, no data were readily available from which to develop a CH_4 emission factor. The emission factor for CO on a mass basis was assumed to be the same as for wood-fired industrial boilers. A NO_x emission factor based on energy input was available.

For MSW-fired units, the NO_x emission factor is the same on an energy input basis for small modular and mass-burn boilers (U.S. EPA, 1982b). However, on an energy output basis the factors differ because the efficiency of mass burn units is estimated to be higher than that of small modular units. The CO emission factors for both mass-burn and small modular MSW facilities are based on test data (Shindler, 1987). No data were readily available for CH_4 emissions from MSW industrial boilers.

Cost

The basis for the cost estimates in Table 13 are summarized in Table 14. Table 14 includes the boiler size in terms of inlet fuel energy, the capital cost, and the non-fuel annual costs. These costs were levelized using an economic life of 30 years, an interest rate of 5 percent, and a capacity factor of 0.55. The costs are in 1985 dollars, and exclude fuel cost. As was the case for utility sources, representative capacities were selected as the basis for cost estimates unless limited availability of cost data required the use of arbitrary capacities. Although the selection of capacity impacts the energy-based cost due to economies of scale, the costs developed for this project, as noted in Section 2, are intended to be approximately representative. A more detailed cost analysis is beyond the scope of this project.

EMISSION CONTROL TECHNOLOGIES

Emission control technologies for industrial boilers and their performance and cost parameter estimates are summarized in Table 15. Table 15 includes the control technology code, efficiency penalty, cost, emission reduction efficiency, and availability date.

Six different control technologies were evaluated. For many of these, the cost, efficiency penalty, and emission reduction efficiency vary significantly for different boilers. The efficiency penalty and emission reduction efficiencies for low excess air, overfire air, low NO_x burners, ammonia injection, and selective catalytic reduction are discussed in Section 3. The costs for these technologies applied to industrial boilers differ, however, from costs for applications to utility boilers, primarily due to economies of scale.

TABLE 14. INDUSTRIAL BOILER SOURCE COSTS[a]

Fuel	Capacity (10^6 Btu/hr input)	Capital Cost ($1,000)	Annual Cost[b] ($1,000)
Natural Gas	100	2,400	455
Distillate Oil	100	2,440	455
Residual Oil	100	2,420	455
Coal	100	9,000	865
Wood	30	2,950	460

[a] Costs in 1985 dollars.

[b] Excludes fuel costs.

Source: U.S. EPA, 1982a.

TABLE 15. INDUSTRIAL BOILER EMISSION CONTROLS PERFORMANCE AND COSTS

Technology	Code	Efficiency Loss (%)	Cost[a] ($/J End-Use)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
Low Excess Air	I1	-0.5	6.8E-12	Negligible	Negligible	Negligible	N/A	15	1970
Overfire Air - Coal	I2	0.5	4.4E-12	Negligible	Negligible	Negligible	N/A	25	1970
Overfire Air - Gas	I3	1.25	4.4E-12	Negligible	Negligible	Negligible	N/A	40	1970
Overfire Air - Oil	I4	0.5	4.4E-12	Negligible	Negligible	Negligible	N/A	30	1970
Low NO_x Burner - Coal	I5	0.25	1.5E-11	Negligible	Negligible	Negligible	N/A	35	1980
Low NO_x Burner - Oil	I6	0.25	3.5E-11	Negligible	Negligible	Negligible	N/A	35	1980
Low NO_x Burner - Gas	I7	0.25	3.5E-11	Negligible	Negligible	Negligible	N/A	50	1980
Flue Gas Recirculation	I8	0.5	1.1E-10	Negligible	Negligible	Negligible	N/A	40	1975
Ammonia Injection	I9	0.5	1.8E-10	Negligible	Negligible	Negligible	N/A	60	1985
SCR - Coal	I10	1	1.1E-09	Negligible	8	Negligible	N/A	80	1985
SCR - Oil, AFBC	I11	1	5.8E-10	Negligible	8	Negligible	N/A	80	1985
SCR - Gas	I12	1	2.0E-10	Negligible	8	Negligible	60	80	1985
Retrofit LEA	I13	-0.5	9.0E-12	Negligible	Negligible	Negligible	N/A	15	1970
Retrofit OFA - Coal	I14	0.5	7.2E-12	Negligible	Negligible	Negligible	N/A	25	1970
Retrofit OFA - Gas	I15	1.25	7.2E-12	Negligible	Negligible	Negligible	N/A	40	1970
Retrofit OFA - Oil	I16	0.5	7.2E-12	Negligible	Negligible	Negligible	N/A	30	1970

TABLE 15. (Continued)

Technology	Code	Efficiency Loss[a] (%)	Cost[b] ($/J End-Use)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
Retrofit LNB - Coal	I17	0.25	2.4E-11	Negligible	Negligible	Negligible	N/A	35	1980
Retrofit LNB - Oil	I18	0.25	5.4E-11	Negligible	Negligible	Negligible	N/A	35	1980
Retrofit LNB - Gas	I19	0.25	5.4E-11	Negligible	Negligible	Negligible	N/A	50	1980

[a] All costs in 1985 dollars.

N/A = not available.

Efficiency Penalty

For a more complete discussion of efficiency penalties, which are assumed the same as for utility boilers, see Section 3. The efficiency penalties for the industrial boiler emission control technologies were taken directly from the literature for low excess air, overfire air, low NO_x burners, and ammonia injection as discussed for utility sources. The efficiency penalty for SCR was estimated in the same manner as for utility sources.

Flue gas recirculation has roughly a 0.5 percent impact on industrial boiler efficiency (Kim et al., 1979).

Removal Efficiencies

The removal efficiencies for low excess air, overfire air, low NO_x burners, ammonia injection, and SCR are estimated to be the same for industrial boilers as for utility boilers, as discussed in Section 3. Flue gas recirculation is capable of about 40 percent reduction of NO_x for oil- and gas-fired boilers. No impact was reported for CO or hydrocarbons (Kim et al., 1979).

Costs

The boiler size, capital cost, and nonfuel annual costs assumed to calculate each of the control technology costs are summarized in Table 16. These costs are in 1985 dollars and were levelized using an economic life of 30 years, an interest rate of 5 percent, and a capacity factor of 0.55. In all cases, the same capacity factor was used for industrial boiler emission source and controls. It was not possible in all cases to use the same source category in the cost estimates for a particular source and the corresponding control, due to limited availability of data.

TABLE 16. INDUSTRIAL BOILER EMISSION CONTROL COSTS[a]

Technology	Source Category (10^6 Btu/hr input)	Capital Cost ($1,000)	Annual Cost ($1,000)
Low Excess Air	100	67	1.2
Overfire Air	1,090	168	8.4
Low NO_x Burner	100	124	6.2
LNB - Coal	1,530	1,270	64
Flue Gas Recirculation	100	39	40
Ammonia Injection	200	350	120
SCR - Coal[b]	100	2,600	121
SCR - Oil[b]	750	8,900	3,700
SCR - Gas	100	445	58
Retrofit LEA	Ratio of retrofit to new cost is 1.32		
Retrofit OFA	Ratio of retrofit to new cost is 1.64		
Retrofit LNB	Ratio of retrofit to new cost is 1.54		

[a] All costs in 1985 dollars.

[b] SCR costs calculated from an algorithm based on Bauer and Spendle, 1984; other data from Kim et al., 1979.

SECTION 5
KILNS, OVENS, AND DRYERS

Performance estimates were developed for seven sources and five controls as part of the kilns, ovens, and dryers category. The sources include lime/ cement kilns, coke ovens, and dryers. Control technologies were identified for these sources. This section discusses the development of efficiency and emission factor estimates for kilns, ovens, and dryers. The dryers discussed in this section exclude coal dryers, which are discussed with other fuel production emission sources in Section 6. Performance and cost parameters for emission control technologies for these sources are also discussed in this section.

SOURCES

The performance parameters for each of the sources included in this category are summarized in Table 17. Indicated in the table are some of the industries in which these emission sources are commonly found. A range of values for the thermal efficiency of kilns and dryers is given. The emission factors are given in grams of pollutant emitted per gigajoule (g/GJ) of input fuel energy for these emission sources. The emission factor quality rating is given to the right of each emission factor. The appropriate control technologies for each source are noted by control code in the last column of the table.

Efficiency

The thermal efficiency of a kiln or dryer is the percent of the input fuel energy that is used to heat the material charge within the kiln. Kiln efficiencies range from about 45 percent to 80 percent, but typically are within 65 percent to 75 percent. Dryer efficiencies range from about 30 percent to 65 percent depending on the temperature at which drying occurs. The overall efficiency of an industrial facility containing a kiln or dryer can be improved by recovering the waste heat from the kiln or dryer for use in other equipment (Perry and Chilton, 1973).

TABLE 17. KILNS, OVENS, AND DRYERS SOURCE PERFORMANCE

			Emissions Factors (g/GJ input energy) and Data Quality Ratings (A - E)					
Industry	Source	Thermal Efficiency (%)	CO_2	CO	CH_4	N_2O	NO_x	Controls[a]
Cement, Lime	Kilns -Natural Gas	65-75	176,000 C	75 E	1 E	N/A	1000 E	K1, K2, K4, K5
Cement, Lime	Kilns - Oil	65-75	196,000 C	75 E	1 E	N/A	500 D	K1, K2, K4, K5
Cement, Lime	Kilns - Coal	65-75	228,000 C	75 E	1 E	N/A	500 D	K1, K2, K4, K5
Coking, Steel	Coke Oven	N/A	50,000 C	200 E	1 E	N/A	N/A	K3
Chem. Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Natural Gas	30-65	51,000 B	10 E	1 E	N/A	52 E	K1, K2
Chem. Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Oil	30-65	70,000 B	15 E	1 E	N/A	160 E	K1, K2
Chem. Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Coal	30-65	102,000 B	170 E	1 E	N/A	215 E	K1, K2

[a] Control codes are defined in Table 18.

To calculate energy-specific emission factors in some cases it is necessary to convert emission factors from a per unit product to an energy basis. Although the thermal efficiency indicates the percent of the input fuel energy that is used to heat the process feed material, a more useful parameter for converting emission factors from a product to an energy basis is the product unit-specific energy requirement. The product unit-specific energy requirement is the amount of energy required to produce one ton of product. For lime and cement kilns, the fuel energy requirement varies significantly depending on whether the process is wet, dry, or involves a precalciner or preheater. A typical range of energy requirements for either lime or cement kilns is roughly 3 MMBtu/ton to 9 MMBtu/ton of cement clinker or quicklime. The lower values are typical of dry processes, and the higher values are typical of wet processes. No data were readily available for the global distribution of wet, dry, and precalciner kiln facilities; a nominal value of 5 MMBtu/ton quicklime or cement clinker was selected as representative of all kilns (Muehlberg and Shepard, 1977).

For coke ovens, a nominal value of 2.78 MMBTU of fuel energy per ton of coke was used (Katari and Gerstle, 1977).

Emission Factors

The emission factors for kilns are based on a review of test data. No data were readily available for the emissions from coke ovens due to fuel combustion. No data were readily available for emissions from dryers; however, the emissions from dryers were assumed to be the same as for industrial and small boilers, primarily because it is assumed that the combustion conditions in the dryer combustor and in small boilers are similar.

The emissions from cement and lime kilns include CO_2 from the calcination of calcium carbonate in limestone and CO_2 from fuel combustion. The amount of CO_2 evolved from calcination on an energy input basis is sensitive both to the amount of carbon contained in the kiln feed per ton of product produced and to the fuel energy required to produce a ton of product. For lime kilns, the amount of CO_2 evolved per ton of feed may range from roughly 870 to 960 lb, depending on whether the limestone has a low magnesium content. Dolomitic limestone, which contains roughly 30 to 45 percent magnesium carbonate, has higher CO_2 emissions from calcination (Doumas et al., 1977). For the purpose of estimating emissions for lime kilns, a nominal value of 900 lb CO_2 per ton of limestone feed is assumed. Converting to a product basis, roughly 1640 lb of CO_2 is emitted per ton of quicklime product, based on a requirement of 1.8 tons of feed per ton of product.

For cement, which has a slightly lower calcination CO_2 emission rate than does lime, a value of 790 lb CO_2 per ton of feed is used, based on the assumption that 90 percent of the feed limestone is calcium carbonate. This emission rate is equivalent to 1310 lb CO_2 per ton of cement clinker.

Using the nominal energy requirement of 5 MMBtu per ton of product, the energy basis CO_2 emission rate from calcination is 113,000 g/GJ for cement kilns and 141,000 g/GJ for lime kilns. A value of 125,000 g/GJ differs by about 10 percent from the nominal values for cement and lime and is used in this analysis as a representative emission rate for calcination for both types of kilns.

The emission of CO_2 from fuel combustion in kilns was calculated for coal, residual oil, and natural gas using the fuel properties in Table 5, and is included, along with the emission rate from calcination, in the total CO_2 emission factors in Table 17. Because CO_2 emissions from lime and cement kilns are extremely high compared to other combustion sources, CO and CH_4 emissions were not included in the carbon balance.

The emissions of NO_x, CO, and CH_4 in kilns are subject to variability due to differences in fuel properties, kiln system design, and operating parameters. Data on emission factors are limited and include test data from both lime and cement kilns. Data were available for a rotary lime kiln, and dry, wet, and precalciner process cement kilns. However, the quality and quantity of the data did not justify developing separate emission factor estimates for different kiln configurations and processes. To develop nominal estimates for this project, values from several tests were simply averaged to estimate representative, order-of-magnitude emission factors.

For coal-fired kilns, 10 data points were averaged to obtain a rough estimate of 500 g NO_x per GJ of input fuel energy. The data ranged from about 200 ng/J to 600 ng/J. For oil, an average of four data points yielded the same result. For natural gas, a review of six data points, ranging from about 400 to 800 ng/J, resulted in an approximate estimate of 1000 g/GJ for NO_x, with a range of about 300 to 1,600 ng/J. The emission factor for CO for all fuels was assumed to be approximately 75 g/GJ, which represents a reasonable upper bound on the CO emissions for most kilns, although a few appear to have higher emissions (Tidona et al., 1983; Benson and Hunter, 1986).

The CH_4 emissions for kilns were estimated in the same manner as those for dryers by reviewing data from AP-42 for industrial and small boilers. These factors, converted to an energy input basis using the fuel properties from Table 5, ranged from 0.65 g/GJ for coal to 1.3 g/GJ for natural gas. Because these emission factors are small and are similar in value, the emission of CH_4 is estimated to be roughly 1 g/GJ for all fuels.

The NO_x and CO emission factors for dryers were similarly estimated from AP-42 emission factors for industrial and small boilers.

Coke ovens typically burn coke oven gas. No data were readily available for the continuous emissions from coke ovens due to combustion of coke oven gas. However, data are available in AP-42 for the emissions of CO and NO_x during charging of coal and pushing of coke in the coke oven. The emissions of NO_x from this aspect of coke production are low compared to other sources, and are likely to be insignificant compared to NO_x emissions from combustion of coke oven gas. CO emissions, however, are significant from the charging process, and the estimate in Table 17 is calculated from the mass basis emission rate from AP-42 and the nominal value of 2.78 MMBtu of fuel energy per ton of coke. The CO_2 emission rate is calculated based on the properties of coke oven gas in Table 5.

CONTROLS

Several control technologies applicable to kilns, ovens, and dryers are shown in Table 18. Table 18 includes the control technology code, the thermal efficiency penalty, the cost excluding fuel on an energy input basis, the removal efficiency for each pollutant, and the availability date.

Both low excess air and low NO_x burners are applicable to kilns and dryers. The cost of low excess air is based on an oxygen analyzer and control system for a 300 MMBtu/hr heat input kiln operating 8,000 hours per year. The efficiency penalty of -6.4 percent reflects the increased thermal efficiency obtained with low excess air operation, due to a reduction in the flue gas volume flow rate. Typically, low excess air does not result in significant increases in emissions of CO for moderate levels of NO_x control; therefore, negligible impacts are assumed for all species except NO_x. The

TABLE 18. KILNS, OVENS, AND DRYERS EMISSION CONTROLS PERFORMANCE AND COSTS

Technology	Code	Efficiency Loss (%)	Cost[a] ($/J Input)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
LEA - Kilns, Dryers	K1	-6.4	8.0E-13	Negligible	Negligible	Negligible	N/A	14	1980
LNB - Kilns, Dryers	K2	0	2.6E-13	Negligible	Negligible	Negligible	N/A	35	1985
SCR - Coke Oven	K3	1	9.5E-10	Negligible	8	Negligible	60	80	1979
Nitrogen Injection	K4	N/A	N/A	N/A	N/A	N/A	N/A	30	1990
Fuel Staging	K5	N/A	N/A	N/A	N/A	N/A	N/A	50	1995

[a] All costs in 1985 dollars.

N/A = not available.

cost of low NO_x burners is based on the difference in cost between standard and low NO_x burners for a 300 MMBTU/hr heat input kiln. As for low excess air, the impact on all species except NO_x is negligible when kilns are operated correctly (Carter and Benson, 1984).

Selective catalytic reduction has been applied to coke ovens in Japan. Costs for SCR applied to coke ovens were not readily available. As an order-of-magnitude estimate, it was assumed that the cost of SCR on a unit energy basis for an internal combustion engine approximates the cost of SCR for a coke oven. The removal efficiencies for SCR have previously been discussed in Section 3.2 (Ando, 1983).

Two advanced technologies for kilns were identified. Both nitrogen injection and fuel staging technologies are in the development phase. The only information readily available was the impact of these two technologies on NO_x. Nitrogen injection may be capable of roughly 30 percent NO_x removal, whereas fuel staging may be able to achieve 50 percent NO_x reduction (EPRI, 1986). No information was readily available for the effect of these two technologies on other pollutants.

SECTION 6
FUEL PRODUCTION

This section includes most major sources of greenhouse gases that are emitted in the production of coal, oil, gas, and wood fuels. In general, the key sources included here are: coal mining and processing operations, oil and gas drilling and transport operations, oil refining, oil shale and coal liquefication production operations, and charcoal production. Since oil refining operations include a large and diverse number of individual sources, a composite emission factor was developed based on a "model refinery" configuration. Use of this single factor can simplify the emissions estimating procedure in global models.

SOURCE DESCRIPTIONS, EMISSION FACTORS AND EFFICIENCY DATA

Table 19 summarizes the emission factors and efficiency data for key fuel production sources. As the table shows, several significant sources of greenhouse gases exist in the fuel production industry. These sources are organized in the table and in the remainder of this section by fuel type as listed below:

- Oil Production Sources
  - petroleum refining
  - oil shale retorting
  - wellhead venting
- Gas Production Sources
  - gas transmission systems
- Coal Production Sources
  - active mines
  - coal drying
  - coal gasification
  - coal liquefication
- Wood-Related Sources
  - charcoal production

Brief process descriptions and a discussion of emission factor development procedures used for each category are discussed in the next four

TABLE 19. FUEL PRODUCTION SOURCE PERFORMANCE

Source	Efficiency (%)	Emissions Factors and Data Quality Ratings (A - E)[a]					Controls[b]
		CO_2	CO	CH_4	N_2O	NO_x	
Gas Refining	N/A	N/A	Negligible D	Negligible D	N/A	Negligible D	
Petroleum Refining	N/A	23,400 D g/bbl crude	1730 D g/bbl crude	0.948 D g/bbl crude	N/A	49 D g/bbl crude	See Table 21
Coal Cleaning	N/A	4,719 B g/ton coal mined	N/A	N/A	N/A	37 C g/ton coal mined	
Oil Shale-Surface	78	15,000 C g/GJ out	17 C g/GJ out	23 C g/GJ out	N/A	61 C g/GJ out	F1
Oil Shale - In-situ	60	1,500 C g/GJ out	0.6 C g/GJ out	8.6 C g/GJ out	N/A	20 C g/GJ out	F1,F2,F3,F5,F6
Lurgi Gasification	65	56,000 D g/GJ out	64 C g/GJ out	N/A	N/A	150 C g/GJ out	F8
Liquefaction Acid Gas	66	23,000 C g/GJ out	2.5 C g/GJ out	N/A	N/A	trace C	

TABLE 19. (Continued)

Source	Efficiency (%)	Emissions Factors and Data Quality Ratings (A - E)[a]					Controls[b]
		CO_2	CO	CH_4	N_2O	NO_x	
Charcoal Production	N/A	68,000 E g/GJ out	5,800 D g/GJ out	1,700 D g/GJ out	N/A	410 D g/GJ out	F9
Natural Gas Transmission	N/A	486 D g/GJ out	2.4 D g/GJ out	2.5 D g/GJ out	N/A	10.6 D g/GJ out	F22,F23,F24
Active Coal Mines	N/A	N/A	N/A	4,920 D g/ton coal mined	N/A	N/A	
Natural Gas Leaks	N/A	N/A	N/A	5.72 E g/m^3 gas marketed	N/A	N/A	
Natural Gas Vented	N/A	N/A	N/A	0.57 E g/m^3 gas marketed	N/A	N/A	

[a] For a discussion of the emission factor data quality ratings, see Section 2.

[b] Control codes are defined in Table 20.

N/A = Not available.

subsection, followed by presentation of available energy efficiency data for all sources covered.

Oil Production Sources

Petroleum refining--

The petroleum refining industry converts crude oil from wells into products such as liquefied petroleum gas, gasoline, kerosene, diesel and aviation fuel, fuel oils, and lubricating oils. Configurations of refineries and types of processes used within refineries may vary widely on a global scale. However, basic refinery processes may be categorized generally as:

- separation processes (such as distillation),
- conversion processes (such as cracking, reforming, alkylation, and coking),
- treating processes (such as hydrodesulfurization and hydrotreating), and
- feedstock and product handling.

Fugitive hydrocarbon emissions from feedstock and product handling operations, such as valves, flanges, pump and compressor seals, and transfer operations consist mainly of hydrocarbons and are not within the scope of this study.

Several different emission sources exist within each of these process areas, so a single "model refinery" emission factor was developed to simplify the global modeling effort for the Reports to Congress. First, the major sources of greenhouse gases in most refineries were identified (U.S. EPA, 1985). These major sources are:

- vacuum distillation,
- catalytic cracking,
- thermal cracking, and
- process heaters.

Emissions from viscosity-breaking (visbreaking) and delayed and fluidized cooling processes may be significant. However, data were not readily available for these process emissions so they were not included here. An emissions factor for a "model refinery" was developed by aggregating the emissions from three of these four major sources. For some of these sources, process emissions were weighted based on the sources' occurrence and use within the industry. Key assumptions and data associated with estimating emissions from each source are listed below.

Vacuum Distillation--Emissions result from the column condensers. Uncontrolled CH_4 emissions for column condensers on a per barrel crude basis were drawn from AP-42 hydrocarbon emissions tables (U.S. EPA, 1985). A statement was made at the bottom of the table that less than 1 percent of the hydrocarbon emissions were CH_4; 1 percent was assumed.

Catalytic and Thermal Cracking--Two main types of catalytic cracking are fluidized bed and moving bed $(\text{Thermofor})^R$ catalytic cracking (FCC and TCC). Emission points are the catalyst regenerator. Carbon monoxide, CH_4, and NO_x emissions were given on a per barrel (bbl) of cracker feed basis for both os these processes (U.S. EPA, 1980). A ratio of 0.289 bbl catalytic cracker feed per bbl crude oil was used to convert the emission factor to a refinery crude feed basis. This ratio was obtained from a typical refinery flow diagram (U.S. EPA, 1980).

Since not all individual refineries contain both FCC and TCC catalytic cracking processes, U.S. refinery flow data were used to estimate the relative weight of these process emissions. In 1979, 94 percent of the U.S. total catalytic cracker feed entered FCC units, and 5 percent entered TCC units. The remaining 1 percent entered Houdriflow^R (HCC) units for which emissions data were unavailable. Emissions from each cracker type were assigned relative weights using this 95-5 split to yield a "weighted" emission factor.

Process Heaters--Process heaters are perhaps the largest source of emissions within a refinery and are used in a number of different process areas. These areas were first identified and then the fraction of the total refinery feed to each of these areas was estimated based on a flow diagram for a typical U.S. refinery and shown below (U.S. EPA, 1980).

Process Areas with Heaters	Fraction of Refinery Flow to Heaters (bbl feed/bbl crude)
Atmospheric distillation	1.0
Vacuum distillation	.420
Delayed choking	.170
Visbreaking	.170 (assumed value)
FCC	.284
Hydrocracking	.057
Gas/Oil hydrodesulfurization	.035
Hydrotreating	.057 (assumed value)
Catalytic reforming	.201
Alkylation	.066
Isomerization	.008
Hydrodesulfurization	.066 (assumed value)

Process heater emission factors for oil- and gas-fired heaters were available on a pounds of pollutant per barrel of process heater feed basis (U.S. EPA, 1980). They were then assigned weights according to their natural gas-residual oil fraction of occurrence: refineries generally use natural gas to fuel 90 percent of their heaters and residual oil to fire the remaining 10 percent. These factors were next normalized to a per barrel of crude feed into the refinery using the factors listed above. The CO_2 emission factors for the fired heaters are based only on the fuel properties of natural gas and residual oil; i.e., CO and CH_4 are neglected in the carbon balance. CO_2 calculated for these two fuels was assigned weights using the 90 to 10 percent split described above.

Finally, the weighted process heater factors for the process areas listed above were summed to yield total process heater emissions for a typical refinery.

Oil Shale Retorting--

Emissions factors are reported for surface and *in situ* oil shale retorting, which is the removal of shale oil from its shale matrix by heating with combustion, either above or below ground, respectively (UNEP, 1985). Some of the released shale oil is used for the combustion in this process, and the combustion gases are vented.

The emission factors in Table 19 for CO_2, CO, CH_4, and NO_x for surface and *in situ* shale retorting are based on the total estimated emissions from a 50,000 bbl/day plant, converted to an energy basis using the heating value of crude shale oil from Section 2 (Table 5). The CH_4 emission factor for both sources was assumed to be the same as the total hydrocarbon emission factor because CH_4 comprises most of the hydrocarbon emissions from retorting (UNEP, 1985).

Wellhead Venting--

With rising gas prices, the volume of vented gas in the United States has fallen steadily since 1960. However, some venting of gas at the wellhead continues in the United States, usually involving gas brought up with associated oil which is not economically recoverable. Maintenance and unscheduled downtime also result in the need to vent or flare gas.

Methane emissions from vented natural gas pose a similar problem to that of natural gas leaks in that data on the breakdown between natural gas vented and natural gas flared at the wellhead are not readily available. In the United States, 0.4 percent of the total gas production in 1985 was flared or vented (AGA, 1986). Most States that have a gas production industry require that gas be flared rather than vented; thus, the American Gas Association estimates that at least about 0.1 percent of the total gas produced in the United States is vented (AGA, 1986). Assuming 88.3 volume percent CH_4 in natural gas, this corresponds to 0.572 grams of methane vented per cubic meter of marketed natural gas. Again, the U.S. percentage of natural gas vented at the wellhead may not reflect the global situation. One source indicates that "the lack of markets and infrastructure for using natural gas as a fuel leads to massive flaring at oil fields in some remote locations" (Marland and Rotty, 1984).

Gas Production Sources

Compared to oil related sources, there are relatively few sources of emissions in gas production. However, the few sources that do exist are not insignificant with regard to their total emissions. Gas transmission system leaks, and pipeline compression/transport engine emissions are the major sources. Acid gas flares at gas refining facilities are a potentially significant source of CO_2 but few data were available with which to calculate CO_2 emissions. Emissions of other gases from gas refining are negligible, according to AP-42.

Pipeline Leaks--

In gas transmission pipeline systems, greenhouse gas emissions occur from two main sources:

- pipeline system leaks, and
- transport/compression engines.

Gas pipeline systems leak methane emissions to the atmosphere, primarily from valves, flanges, and corroded transmission lines. No firm data can be found on the amount of natural gas leaked or lost. Lost and unaccounted for gas is about 2 percent of marketed gas production in the United States each year, but this includes gas unallocated due to meter inaccuracies, theft, and temperature and/or pressure differences. It is estimated that unallocated gas accounts for 50 percent or more of the unaccounted for gas in the United States. Thus a conservative estimate of gas leaked would be 1 percent of marketed gas production. Assuming that 88.3 percent (by volume) of this natural gas is methane, the amount of CH_4 leaked into the atmosphere would be 0.883 percent of the marketed gas production. This corresponds to 5.72 grams of methane leaked per cubic meter of marketed natural gas, using the assumed density of 647.7 grams/m^3.

Because data are not readily available for global methane leaks, it is not known whether methane loss for the United States is a valid gauge for world methane loss.

Transport/Compression Engine Emissions--

Emissions from internal combustion engines and gas turbines in the pipeline/transport system occur as a result of burning fossil fuels and the emission specie is primarily CO_2. The NO_x, CO, and hydrocarbon emission factors for natural gas internal combustion engines and gas turbines and diesel internal combustion engines used in pipelines are available on an energy input basis (Shih et al., 1979). A CH_4 emission factor for internal combustion engines was determined by assuming that 10 percent of total hydrocarbon emissions from diesel-fueled engines is methane and 80 percent of total hydrocarbon emissions from natural gas fueled engines is methane (U.S. EPA, 1977b). The emission factor for CH_4 from a natural gas-fired gas turbine is taken directly from test data. The CO_2 emission factors for internal combustion engines and gas turbines are based on carbon balances including CO and CH_4 using appropriate fuel properties from Section 2 (Table 5).

The emissions for the natural gas, internal combustion engines and gas turbines and diesel internal combustion engines were then aggregated according to their use (Shih et al., 1979). Natural gas pipelines use approximately 3 percent of the gas transmitted to run the compressor engines (Shih et al., 1979; Marland and Rotty, 1984).

Coal Production Sources

Active Coal Mines--

Methane present within coal seams may be liberated when the seams are penetrated to mine the coal. Methane is vented in a fairly pure form from active coal mines. Current literature outlines various ways to estimate the amount vented based on an emission factor of cubic meters of methane per ton of coal mined. Some authors give one general emission factor, whereas others present different factors for the different grades of coal mined: anthracite, bituminous, subbituminous, and lignite. Some vented methane is used onsite in coal-drying, for example, and it is not clear whether the various literature estimates include this methane or not. It was assumed here that the emission factors reported in the literature estimate only what is vented to the atmosphere. If this is incorrect, factors presented in this report may be slightly overestimated.

Emission factors for methane from active coal mines from several current references are summarized here:

CH_4 Emission Factor	Reference
6.25 m^3/ton bituminous and anthracite coal mined	Marland and Rotty, 1984
2.5 m^3/ton subbituminous coal mined	
1.25 m^3/ton lignite	—
6.2-15.6 m^3/ton bituminous and anthracite coal mined	Byrer et al., 1987; Boykins et al., 1981
<6.2 m^3/ton subbituminous and lignite coal mined	—
18-19 m^3/ton coal mined	Crutzen, 1987; U.S. DOE, 1987

Based on engineering judgment, a reasonable "middle-of-the-road" value appears to be 7.6 m^3/ton coal mined. With an assumed density of 647.7 grams/cubic meter, the emission factor on a mass basis is 4,922 grams CH_4 per ton of coal mined.

Coal Drying--

The drying of coal can be accomplished with a fluidized bed dryer, in which coal is suspended and dried above a perforated plate by rising hot coat combustion gases. Data were not available for flash and multilouvered dryers.

Uncontrolled dryer exhaust emissions were taken from AP-42 on the basis of a ton of coal dried. The CO_2 emission factor was calculated from ten data points for the CO_2 concentration in the exhaust gas from coal dryers and the corresponding flue gas flowrates. Dryer exhaust gases are the only source of greenhouse gases in a coal drying process. Since not all coal mined requires drying, these emissions were weighted by the ratio of tons of coal dried per ton of coal mined. To calculate this factor, 1975 U.S. coal cleaning market data were used. Of the coal mined, 49.3 percent underwent a cleaning operation (U.S. DOE, 1987).

Coal Gasification--

Gasification, in simple terms, is the combination of coal and steam to form CO, H_2, and CH_4. The heat to drive the gasification process is maintained by coal combustion. A Lurgi gasifier, which contains a counter-current moving bed of coal and steam, is used as the basis for the emission factors presented in Table 19. Reported emission factors are for an entire Lurgi plant.

The emission factors for Lurgi gasification were calculated from data on estimated annual emissions from a 250 x 10^9 Btu/day Lurgi plant (U.S. EPA, 1978). The CO_2 emission factor was calculated with a carbon balance by balancing the input coal carbon with the output synthesis gas carbon (which was reported as roughly 65 percent of the synthesis gas) and the output carbon contained in the CO emissions. The input coal was calculated based on a daily output of 250 x 10^9 Btu, the process efficiency reported in Table 19, and the coal heating value presented in Section 2 (Table 5).

Coal Liquefaction--

Liquefaction processes produce usable liquid products from coal. A major source of emissions from liquefaction processes is the acid gas flare that burns a vent stream of reaction by-products.

The CO_2, CO, and NO_x emission factors for coal liquefaction are based on emissions data for the Synthoil®, H-Coal®, and Exxon Donor Solvent® Processes (Parker and Dykstra, 1978). The Synthoil® process has four product streams (product oil, light fuel oil, liquid by-products, and by-products gas) and the H-Coal® and Exxon Donor Solvent® each had three product streams (naphthas, fuel gas, and heavy oils). Product flow rates and heating values of these products were given for each of the three processes. These were used to convert the emissions from a mass to an energy output basis.

Wood-Related Sources

The production of charcoal is performed by a controlled combustion of wood in a kiln or continuous furnace. Emissions result from the wood combustion flue gases. The emission factors for CO, CH_4, and NO_x from charcoal production were readily available, and were converted to an energy basis using the estimated heating value of charcoal from Section 2 (Table 5) (Moscowitz, 1978). The CO_2 was calculated by a carbon balance using the following: carbon in wood (reported as roughly 50 percent), carbon out in CO and CH_4, and carbon out in produced charcoal (roughly 87 percent). It was assumed the remaining carbon is available for CO_2 formation.

Efficiency Data

The efficiencies for surface and *in situ* oil shale retorting are estimates of the percent of shale oil recovered from shale during the retorting process. The estimate for the surface retort conversion efficiency, 78 percent, is based on an average of the Paraho Direct, Paraho Indirect, and TOSCO II retort conversion efficiencies. The estimate for the in-situ retorting conversion efficiency, 60 percent, is based on a single *in situ* retorting conversion efficiency value (U.S. EPA, 1980).

The efficiency for coal liquefaction is an average of the overall thermal efficiencies for three liquefaction processes; Synthoil®, H-Coal®, and Exxon Donor Solvent® Processes. The overall thermal efficiency is defined in this content as the ratio of the heating value of all products and by- products to the heating value of all input feed materials (Parker and Dykstra, 1978). This average is 66 percent.

The efficiency for Lurgi gasification is the coal-to-product gas thermal efficiency, which is defined as the ratio of the heat content of coal to the heat content in the product gas. This value is 65 percent (U.S. EPA, 1978).

The efficiency for pipeline gas turbine is based on conversion of fuel energy to shaft horsepower. The efficiency of 34 percent for internal combustion engines is based on a typical heat rate of 7500 Btu/hp-hr, which is a commonly assumed heat rate from AP-42.

EMISSION CONTROL TECHNOLOGIES

Emission control technology performance and cost estimates are presented in Table 20. For each of the control technologies, Table 20 includes a control technology code, efficiency penalty, levelized cost on an energy or production basis, emission reduction efficiency, and availability date. The following sections describe each of the categories of data separately. For the model oil refinery discussed previously, a combination of these technologies is applied.

Emission Reduction Efficiency

For several of the fuel production emission sources, limited information was available from which to identify the applicability of control technologies and, in many instances, data were not available from which to estimate the emission reduction efficiencies for various control technologies. Therefore, the removal efficiencies for some controls were assumed to be the same for fuel production sources as for similar sources to which they are applied. This technology transfer was assumed for CO boilers, afterburners, FGR retrofits, SCR retrofits, Nonselective catalytic reduction (NSCR) retrofits, SCA, LEA, and SCA used in conjunction with LEA.

Recall that a single emission factor is used to represent a "model refinery" and that factor includes the emissions associated with many different sources within the refinery. In order to quantify the impact of

TABLE 20. FUEL PRODUCTION EMISSION CONTROLS PERFORMANCE AND COST

Technology	Code	Efficiency Loss[a] (%)	Cost (1985 $)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
Selective Catalytic Reduction (SCR)	F1	N/A	N/A	Negligible	Negligible	Negligible	N/A	80	1999
LEA	F2	N/A	N/A	Negligible	Negligible	Negligible	N/A	15	1985
Two Stage Combustion	F3	N/A	N/A	Negligible	Negligible	Negligible	N/A	30	1985
Water Injection	F4	1	6.4E-11 $/J input	Negligible	Negligible	Negligible	N/A	70	1965
Fast Heat Release	F5	N/A	N/A	Negligible	Negligible	Negligible	N/A	10	1985
NH_3 Injection	F6	N/A	1.6E-13 $/J output	Negligible	Negligible	Negligible	N/A	60	1985
High Temperature Regeneration	F7	N/A	N/A	N/A	99	N/A	N/A	N/A	1985
CO Boiler	F8	N/A	N/A	N/A	99	100	N/A	-125	1985
Afterburner	F9	N/A	$1.87/ton dry wood	-1	90	N/A	N/A	N/A	1985
FGR Retrofit - D.O.	F10	0.5	0.036 $/ bbl crude	N/A	N/A	N/A	N/A	38	1985
FGR Retrofit - Gas	F11	0.5	0.036 $/ bbl crude	N/A	N/A	N/A	N/A	57	1983

TABLE 20. (Continued)

Technology	Code	Efficiency Loss[a] (%)	Cost (1985 $)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
SCR Retrofit - Gas	F12	1	0.424 $/ bbl crude	N/A	N/A	N/A	N/A	69	1983
SCR Retrofit - D.O.	F13	1	0.424 $/ bbl crude	N/A	N/A	N/A	N/A	78	
SCR Retrofit - R.O.	F14	1	0.424 $/ bbl crude	N/A	N/A	N/A	N/A	90	
SNCR-NH_3 Retrofit	F15	0.5	0.069 $/ bbl crude	N/A	N/A	N/A	N/A	53	
SCA - Gas	F16	-0.3	0.006 $/ bbl crude	N/A	N/A	N/A	N/A	60	1979
SCA - R.O.	F17	-0.8	0.056 $/ bbl crude	N/A	N/A	N/A	N/A	34	1979
LEA - Gas	F18	-3.9	0.019 $/ bbl crude	N/A	N/A	N/A	N/A	15	
LEA - R.O.	F19	-4.2	0.019 $/ bbl crude	N/A	N/A	N/A	N/A	28	
LEA & SCA - Gas	F20	-6.7	0.078 $/ bbl crude	N/A	N/A	N/A	N/A	71	1979

TABLE 20. (Continued)

Technology	Code	Efficiency Loss[a] (%)	Cost (1985 $)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
LEA & SCA - R.O.	F21	-6.7	0.078 $/ bbl crude	N/A	N/A	N/A	N/A	53	1979
Pre-Stratified Charge	F22	-3	3.9E-11 $/J input	Negligible	-20	-50	N/A	80	1987
Non-Selective Cat. Red	F23	7	2.8E-10 $/J input	Negligible	15	40	70	90	1984
Selective Catalytic Red.	F24	1	9.5E-10 $/J input	Negligible	8	Negligible	60	80	1985

[a] A negative efficiency loss indicates an improvement in efficiency.

N/A = not available.

adding controls to these many different sources, a composite emission reduction efficiency factor was developed. The reduction efficiencies for NO_x, CO_2, CO, and CH_4 for the "model refinery" were calculated by applying a wide range of control technologies to the individual emission sources. These sources, which were described previously, are shown with a listing of all potentially applicable control technologies in Table 21. The emissions from individual sources after control were summed and compared to the sum of all uncontrolled sources to calculate a refinery-wide reduction efficiency.

Two control scenarios for the model petroleum refinery were investigated. Level 1 represents a well-controlled refinery, and Level 2 represents a baseline-controlled refinery. The controls chosen for these two levels are shown in Table 22. For Level 1, refinery-wide CO_2, CO, CH_4, and NO_x reduction efficiencies are -111.5, 99.0, 100, and 53 percent, respectively. For Level 2, refinery-wide CO_2, CO, CH_4, and NO_x reduction efficiencies are -111.5, 98.8, 43.2, and 12.2 percent, respectively. The CO_2 reduction efficiency increases by 11 percent for both levels because CO and CH_4 destroyed creates additional CO_2.

Several technologies are potentially applicable to oil shale retorting for NO_x control, but are not commercially proven with this source (Ando, 1973; U.S. EPA, 1983). Caution should be exercised when conceptually applying these technologies to retorting. They included: SCR, LEA, two-stage combustion, and lowering the combustion temperature with a fast heat release. Estimated NO_x removal efficiencies are reported in Table 20.

A CO boiler can be applied downstream of several fuel production emission sources such as Lurgi gasification for heat recovery. Although CO boilers result in roughly 100 percent CO emission reduction, they are a source of NO_x and CO_2. For control of CO emissions from charcoal production, an afterburner can be used. The roughly 90 percent decreased in CO using an afterburner is accompanied by a slight increase in CO_2 emissions (Waterland et al., 1982; Kim et al., 1979).

The emission reduction for Prestratified Charge (PSC) and NSCR applied to turbines or internal combustion (IC) engines in pipeline systems is based on limited test data. PSC is capable of about 80 percent NO_x reduction on average, but may result in increases in emissions of CO and CH_4 (Benson and Hunter, 1986). NSCR is capable of 90 percent NO_x reduction on average, and also reduces CO, CH_4, and N_2O, according to limited test data. Although CO

TABLE 21. REFINERY SOURCES AND CONTROLS

	Applicable Control Technologies by Technology Code[a]			
Sources	CO_2	CO	CH_4	NO_x
Vacuum Distillation	--	F8	F8	
Catalytic Cracking	--	F7, F8	F8	
Process Heaters				
Oil	--	F8	--	F14, F15, F17, F19, F21
Natural Gas	--	F8	--	F11, F12, F16, F20

[a] See Table 20 for code descriptions.

TABLE 22. REFINERY CONTROL LEVELS[a]

Sources	Level 1 Well Controlled	Level 2 Baseline
Vacuum Distillation NO_x	None	None
Vacuum Distillation CO	F8	F8
Catalytic Cracking NO_x	None	F8
Catalytic Cracking CO	F8	F8
Process Heaters Natural Gas NO_x	F12	F18
Process Heaters Natural Gas CO	F8	None
Process Heaters Residual Oil NO_x	F14	F19
Process Heaters Residual Oil CO	F8	None

[a] See Table 20 for code descriptions.

and CH_4 emissions are reduced, the increase in CO_2 emissions is not significant (Castaldini and Waterland, 1986).

Efficiency Penalty

The efficiency penalty for flue gas recirculation applied to fired heaters (control codes F10 and F11) was assumed to be the same as the penalty for industrial boilers. The efficiency penalty for SCR and ammonia injection applied to fired heaters was assumed to be the same as the penalty for industrial boilers. The basis of these estimates is discussed in more detail in Section 4.

The efficiency penalty for staged combustion air is taken to be -0.3 percent for gas-fired heaters and -0.6 percent for residual oil-fired heaters, which shows a net gain in efficiency. It is assumed that low excess air also improves the efficiency of refinery gas-fired heaters by 3.9 percent, and enhances the efficiency of residual oil-fired heaters by 4.2 percent (Benson and Hunter, 1986). These levels can be achieved only if the proper air level is attained and maintained. A combination of staged combustion air and low excess air improves efficiency by 6.7 percent for refinery gas-fired heaters and residual oil-fired heaters (Benson and Hunter, 1986).

PSC is essentially a combustion modification to internal combustion engines that stratifies the fuel/air mixture prior to injection in the cylinders, thereby promoting heterogenous firing of the fuel/air mixture. This results in temperature control that limits NO_x formation. Typically, PSC (control code F22) results in approximately a 3 percent decrease in brake-specific fuel consumption when operated at full load (ASME, 1986).

NSCR requires rich-burn operation of an internal combustion engine, which increases brake-specific fuel consumption by about 7 percent (Benson and Hunter, 1986). SCR requires electricity to operate the ammonia injection equipment. A nominal efficiency penalty of 1 percent is assumed.

Efficiency penalties for emission control technologies applied to the remaining sources were not readily available.

Cost

For most controls for which costs were available, the costs were calculated from the data in Table 23, which presents the capital and annual cost for six technologies applied to sources of a given size. For the purposes of this study, the costs for a given technology were assumed to be approximately the same for different fuels. This may result in some inaccuracy in cost estimates. Data for individual fuels were not readily available. The capital costs in Table 23 were levelized using a capital recovery factor of 0.277 for low excess air and staged combustion air, and a capital recovery factor of 0.143 for the other controls, and a capacity factor of 0.6. The costs levelized on the basis of energy input to the fired heaters were converted to a per barrel crude basis by using the typical heat requirement per barrel of crude oil discussed above.

The costs for PSC, NSCR, and SCR are based on a 600 hp engine with a heat rate of 7500 Btu/hp-hr, operating 90 percent of the year. Although the capital costs for PSC and NSCR are similar, NSCR has higher maintenance costs. The cost of SCR applied to an internal combustion engine is roughly the same as the cost of SCR applied to a gas turbine, on an energy input basis. The costs for the gas turbine were developed for a 400 MMBtu/hr input gas turbine operating 90 percent of the year.

The cost for the afterburner control technology in Table 20 is based on a $700,000 capital cost for a 7.5 ton/hour capacity wood charcoal furnace (U.S. EPA, 1979). The cost was levelized using a 5 percent interest rate over 30 years and a capacity factor of 0.55.

TABLE 23. FUEL PRODUCTION EMISSION CONTROL COST

Technology	Source Capacity (MMBTU/hr)	Capital Cost ($1,000)	Annual Cost ($1,000)
Flue Gas Recirculation (Retrofit)	150	256	17
SCR (Retrofit)	150	2,970	252
Ammonia Injection (Retrofit)	150	380	55
Staged Combustion Air	55	54	21
Low Excess Air	55	44	0.2
SCA and LEA	55	98	21

SECTION 7

MOBILE SOURCES AND CONTROL TECHNOLOGIES

Emission factors were developed for six highway and four off-highway transportation technologies. Eight control technologies for several of these sources were identified, and performance and cost estimates were developed. The emission factors and controls cost, reduction efficiency, and availability date are discussed in this section.

MOBILE SOURCE EMISSIONS

Table 24 summarizes the emission factors developed for mobile sources. The emission factors are based on the mass of pollutant emitted per gigajoule of fuel energy input. Included in Table 24 are the emission factors for each of the five gases considered in this study. To the right of each emission factor is its quality rating. The last column indicates by code the applicable control technologies.

The emission sources in Table 24 can be categorized into highway and off-highway sources. Highway sources include light duty gasoline vehicles (LDGV), heavy duty gasoline vehicles (HDGV), light duty diesel vehicles (LDDV), heavy duty diesel vehicles (HDDV), and light duty vehicles fueled with compressed natural gas (CNG) and methanol. The off-highway sources include both jet and gasoline-fueled aircraft, railroad locomotives, and ships.

Highway Source Emissions

Emission factors for NO_x and CO were calculated on an energy input basis for light and heavy duty gasoline- and diesel-fueled vehicles. These emission factors are based on data obtained from Mobile3, a FORTRAN model for the assessment of the impact of highway sources on air pollution containing an extensive database of emission factors and fuel economy (EPA, 1984). The Mobile3 database has been extensively reviewed, and includes also emission factors for vehicles with and without emission controls. The emission factors on an energy input basis can be assumed to be similar from one region of the world to another for uncontrolled vehicles.

TABLE 24. MOBILE SOURCE PERFORMANCE

	Emissions Factors (g/GJ energy input) and Data Quality Ratings (A - E)					
Source	CO_2	CO	CH_4	N_2O	NO_x	Controls[a]
Rail	69,900 B	570 C	13 D	N/A	1,640 C	
Jet Aircraft	72,800 B	120 C	2 E	N/A	290 D	
Aviation--Gasoline	35,900 C	23,500 D	60 E	N/A	80 D	
Ships	70,000 B	320 C	20 D	N/A	830 C	
Light Duty Gasoline Vehicle	54,900 A	10,400 B	36 C	N/A	400 B	T1, T2, T3
Heavy Duty Gasoline Vehicle	41,100 A	19,100 B	60 C	N/A	740 B	T4, T5, T6
Light Duty Diesel Vehicle	73,750 A	340 B	2 D	N/A	300 B	T7
Heavy Duty Diesel Vehicle	73,300 A	600 B	8 D	N/A	1,200 B	T8
Light Duty Methanol Vehicle	53,000 B	8,500 E	15 E	N/A	130 E	
Light Duty Compressed NG Veh.	50,200 B	4 E	120 E	N/A	140 E	

[a] Control codes are defined in Table 25.

Light duty vehicles correspond to passenger cars and light trucks, whereas heavy duty vehicles correspond to various sizes of heavy duty trucks. The emission factors for diesel and gasoline vehicles in Table 24 represent uncontrolled emissions. For the purpose of this study, the emission factors are assumed not to vary with time. A change in emissions can be effected by switching from one level of control to another.

The emission factors for CH_4 for light and heavy duty diesel and gasoline-fueled vehicles are based on AP-42 federal test procedure (FTP) methane offsets. These offsets are CH_4 emission factors, which are given in units of grams CH_4 per mile traveled. The values for methane offsets representing emissions from vehicles driven at low altitudes were converted to energy-based CH_4 emission factors using fuel consumption data from the Mobile3 study. The low altitude methane offsets were assumed to be more representative of global average CH_4 emission factors than the high altitude methane offsets from AP-42. The vehicular emissions of CH_4 have generally decreased in the United States due to the application of increasingly stringent emission control technologies. Therefore, to represent emissions from uncontrolled motor vehicles, the LDGV methane offset for 1967 and prior was used to estimate the LDGV CH_4 emission factor. Emission controls were first required for LDGV in the United States beginning in 1968. Similarly, for HDGV, LDDV, and HDDV, the methane offsets for 1977, 1984, and 1986 and prior were used, respectively, to estimate CH_4 emission factors. These offsets either predate the required application of emission controls in the United States for their respective vehicle classes, or they are unchanged from the offsets for vehicles without emission controls.

CO_2 emissions were calculated using a carbon balance including the CO and CH_4 emission factors and the properties of gasoline and diesel fuel from Table 5. The balances include the fuel carbon as an input, and the emission of CO_2, CO, and CH_4 in the output.

Limited emission test data for N_2O are available for diesel- and gasoline-fueled vehicles (Smith and Black, 1980). However, recently discovered problems with sampling methods for N_2O cast doubt on this existing data base. Consequently, no N_2O emission factors are presented here.

For methanol-fueled light duty vehicles, emissions data were readily available from tests for only two vehicles, a Ford Escort and a Volkswagen Rabbit. The tests were done using the FTP, and the tests of the Ford Escort included tests without a catalyst, which are the basis for the emission factors in Table 24. The CO, CH_4, and NO_x emission factors for light duty methanol vehicles are based on the test data for the Ford Escort. The CO_2 emission factor was calculated including CO, CH_4, and CH_3OH in the carbon balance, using the properties of methanol from Table 5. No data were readily available for N_2O emissions from methanol-fueled vehicles (Smith and Urban, 1982).

The emission factors for light duty compressed natural gas vehicles are based on an average of emissions from a 1980 Dodge Diplomat and a 1979 Chevrolet Impala during FTP tests. Emissions of CH_4, CO, and NO_x were measured, as was fuel consumption. The CO_2 emission factor was calculated based on CO and CH_4, using the technique outlined in Section 2, and the properties of natural gas from Table 5. The emission factors for natural gas-fired vehicles are based on tests of only two vehicles, and should be regarded only as rough estimates (Pennings, 1981).

Off-Highway Source Emissions

The emission factors for rail transportation in Table 24 for NO_x and CO represent a weighted average of emissions of line haul and switching locomotives in the United States. The CH_4 emission factor is based on a weighted average total hydrocarbon emission factor. Line haul locomotives comprise 80.1 percent of all locomotives, the rest being switching locomotives (Ingalls, 1985). The emission factor for methane is based on 10 percent of the emission factor for total hydrocarbons; for diesel engines, over 90 percent of total hydrocarbon emissions are nonmethane hydrocarbons (U.S. EPA, 1977b). No data were available for N_2O emissions from railroad locomotives. The CO_2 emission factor was calculated based on the properties of diesel fuel and a carbon balance including CO and CH_4.

A single engine was selected from which to calculate the jet aircraft emission factors in Table 24. Emission factors for several engine models are available in AP-42; however, information was not readily available from which to calculate a weighted emission factor for all aircraft. The emission factors for jet aircraft are based on the JT8D17 engine manufactured by Pratt and Whitney, which is used on the Boeing 727, Boeing 737, and the McDonnell Douglas DC9. Jet aircraft emissions are usually calculated to approximate the emissions occurring near an airport, based on a typical landing and takeoff (LTO) cycle. For a commercial carrier jet, the typical LTO cycle includes 19.0 minutes in taxi and idle before takeoff, 0.7 minutes during takeoff, 2.2 minutes in climbout, 4.0 minutes in approach, and 7.0 minutes in taxi and idle after landing. During takeoff, the engine is operated at 100 percent power, during climbout the engine is operated at 75 to 90 percent of full power, and during approach the engine is operated at 30 to 40 percent of full power. Emission factors for each engine in AP-42 include emissions during idle, takeoff, approach, and climbout. From these factors, and from fuel consumption data for each of these four modes, emission factors were developed that reflect the average emission throughout a modified landing and takeoff cycle.

To approximate the emissions for an entire flight, the LTO cycle was modified to include additional time during climbout and approach. The time spent in climbout and approach was increased by approximately 30 minutes each to represent a one-hour flight. The effect of this modification on the average emission factors is to decrease CO and CH_4, increase NO_x, and slightly decrease CO_2. The emission factors for CO and NO_x were calculated directly from the AP-42 data, using the modified LTO cycle. Emissions of CH_4 are based on 10 percent of the total hydrocarbon emission factor calculated using the modified LTO cycle. No data were available for the emission of N_2O from jet aircraft engines. The CO_2 emission factor was calculated using the properties of Jet A fuel and a carbon balance as described in Section 2, including CO and CH_4.

The emissions for gasoline-fueled aircraft were calculated in a manner similar to that for jet aircraft. The 0-200 engine, used on Cessna aircraft, was selected as a representative engine for gasoline-fueled piston engine aircraft. The emission factors for this engine are available in AP-42. The LTO cycle for general aviation piston aircraft is 12.0 minutes taxi and idle before takeoff, 0.3 minutes during takeoff, 5.0 minutes during climbout, 6.0 minutes during approach, and 4.0 minutes during taxi and idle after landing. This LTO cycle was extended approximately 15 minutes for both climbout and approach to represent a one-half hour flight.

The emission factors for NO_x and CO calculated directly from the emission factors from AP-42 using the modified LTO cycle. The emission factor for CH_4 is based on 10 percent of the AP-42 emission factor for total hydrocarbons. No data were readily available for N_2O emissions from gasoline aviation engines. The CO_2 emission factor is based on the properties of gasoline and a carbon balance including CO and CH_4.

The emission factors for ships are based on the factors in AP-42 for commercial motorships. The emission factors for NO_x, CO, and total hydrocarbons are based on values for river, coastal, and Great Lakes shipping. The emission factor for CH_4 is based on 10 percent of the AP-42 emission factor for total hydrocarbons. The CO_2 emission factor was calculated from the properties of diesel fuel and a carbon balance as described in Section 2, including CO and CH_4.

MOBILE SOURCE EMISSION CONTROL TECHNOLOGIES

No emission control technologies were readily identified for rail, aviation, and shipping sources. Several technologies were identified and selected for light and heavy duty gasoline and diesel vehicles. These emission control technologies, and their cost, emission reduction efficiencies, and availability dates are given in Table 25.

The emission data listed in Table 25 for highway vehicles are different from other control technologies presented in this report in that they represent comparisons of vehicles with controls to vehicles without controls. The emission reduction efficiencies for highway source controls were estimated by comparing the emissions of vehicles without controls to the emissions of vehicles with controls. The reduction efficiencies for these controls may therefore be different from reduction efficiencies derived by comparing "before and after" emission rates of a single vehicle tested without, and then with, an add-on or combustion modification control.

Emission Reduction Efficiency

The emission reduction efficiencies for the eight control technologies applied to highway sources were estimated by comparing the energy specific emissions of vehicles with controls to vehicles without controls. These estimates are based on data obtained using Mobile3.

TABLE 25. MOBILE SOURCE EMISSION CONTROLS PERFORMANCE AND COSTS

Technology	Code	Cost[a] ($/J End-Use)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
LDGV Engine Control	T1	N/A	-11	36	Negligible	N/A	8	1968
LDGV Oxidation Catalyst	T2	2.0E-10	-17	57	33	-2300	23	1975
LDGV 3 Way Catalyst	T3	2.0E-10	-23	78	44	-3400	44	1980
HDGV Engine Control	T4	N/A	-25	35	52	N/A	31	1978
HDGV Oxidation Catalyst	T5	2.0E-10	-66	90	70	N/A	33	1985
HDGV 3 Way Catalyst	T6	2.0E-10	-71	97	69	N/A	41	1998
LDDV Low NO_x Control	T7	N/A	Negligible	11	-16	N/A	24	1985
HDDV Low NO_x Control	T8	N/A	Negligible	8	Negligible	N/A	41	1987

[a] All costs in 1985 dollars.

N/A = not available.

Data for NO_x and CO were available on an energy-specific basis for each level of control. Data for CH_4 were available from the AP-42 methane offsets discussed above. These offsets were applied to various control levels by comparing the years for which the offsets are valid to the years for which various control technologies were required. For example, in 1967 and before, no controls were required for LDGV. Engine controls were required from 1968 to 1974, oxidation catalysts were required from 1975 to 1979, and three-way catalysts were required beginning in 1980. The appropriate methane offsets for these years from AP-42 were used for each of the control levels. The effect of controls on CO_2 emissions was determined by calculating the CO_2 emission factor for each control level, using a carbon balance including CO and CH_4, and comparing the CO_2 emission factor with controls to the emission factor without controls.

Most tests suggest that N_2O emission from catalyst-equipped LDGV are within a range of 50 to 100 mg/mile. As previously discussed, the N_2O emissions of uncontrolled LDGV, based on a single data point, are roughly 5 mg/mile. Catalysts may promote the partial oxidation of nitrogen to N_2O. For LDGV, the effect of catalysts on N_2O was estimated by assuming an emission rate of 5 mg/mile for vehicles without controls and 100 mg/mile for vehicles with catalyst controls. These emission rates were converted to an energy basis using the same fuel consumption data as for the other pollutants. A comparison of the energy-specific emission factors for N_2O with and without catalyst control resulted in the estimates in Table 25 for LDGV oxidation and three way catalysts. Insufficient information was available for HDGV to justify a similar comparison (Smith and Black, 1980).

Cost

The cost for a catalyst was assumed to be roughly $100 for LDGV. This cost was annualized over 10 years assuming 10,000 miles driven per year at 20 miles per gallon. No difference in cost was assumed between oxidation and three-way catalysts. The cost of catalysts for heavy duty vehicles was assumed to be the same on an energy-specific basis.

SECTION 8
RESIDENTIAL AND COMMERCIAL SOURCES AND CONTROLS

Efficiency and emission factor estimates were developed for nine residential emission sources and 11 commercial emission sources. For both residential and commercial sources, performance and cost estimates were developed for applicable control technologies. This section presents the performance estimates for residential sources. Commercial source efficiency and emission estimates are also discussed as are emission control technologies for both residential and commercial sources. A glossary of terms used in the tables of section appears at the end of this report.

RESIDENTIAL SOURCES

Table 26 presents the efficiencies and emission factors for nine residential emission sources. These sources burn wood, propane and butane, coal, distillate oil, and natural gas. Included in Table 26 is the efficiency, energy input emission factors (unless otherwise noted), emission factor quality rating, and appropriate control codes.

Efficiency

The efficiency of residential sources is the percent of the input energy converted to thermal energy for an end-use. Efficiency data was readily available for only three of the residential emission sources: wood stoves, distillate oil furnaces, and gas heaters. These are the only sources with emission factors reported on an energy output basis. The efficiency of standard wood stoves is estimated to be 50 percent; the efficiency of standard distillate oil furnaces is estimated to be 75 percent; and the efficiency of standard natural gas heaters is estimated to be 70 percent (Castaldini et al., 1981).

Emission Factors

The emission factors for NO_x, CO, and CH_4 for residential sources, unless otherwise noted, were taken directly from AP-42 and converted to an energy

TABLE 26. RESIDENTIAL SOURCE PERFORMANCE

Source	Efficiency (%)	Emissions Factors (g/GJ energy input) and Data Quality Ratings (A - E)[a]					Controls[b]
		CO_2	CO	CH_4	N_2O	NO_x	
Wood Pits	N/A	26,000 C	4,700 B	190 B	N/A	140 B	
Wood Fireplaces	N/A	32,000 C	5,700 D	N/A	N/A	110 D	
Wood Stoves	50	70,000[c] C	17,600[c] D	70[c] E	N/A	190[c] D	R1, R2
Propane/Butane Furnaces	N/A	60,000 A	9 C	1 C	N/A	42 C	
Coal Hot Water Heaters	N/A	103,000 C	17 B	N/A	N/A	150 B	
Coal Furnaces	N/A	102,000 C	460 C	N/A	N/A	220 C	
Coal Stoves	N/A	99,000 C	3,400 B	N/A	N/A	170 B	
Distillate Oil Furnaces	75	83,000[a] A	17[a] B	7[a] B	N/A	65[a] B	R6 - R10, R18 - R24
Gas Heaters	70	71,000[a] A	13[a] B	1[a] E	N/A	61[a] B	R11 - R17

[a] Emission factor units are g/GJ energy output.

[b] Control codes are defined in Table 28.

input basis using the appropriate fuel heating value from Table 5. Emission factors for wood stoves, distillate oil furnaces, and natural gas heaters were converted to an energy output basis using both the fuel heating value and the energy conversion efficiency discussed earlier. No data were available from which to estimate N_2O emissions from residential sources. The CO_2 emission factor for residential wood-fired sources was calculated using a method that accounts for the carbon retained in fly ash during the inefficient combustion typical of these emission sources. For the other emission sources, the CO_2 emission factor was calculated using the methods of Section 2.

The NO_x, CO, and CH_4 emission factors for wood pits were estimated based on AP-42 emission factors for open burning of forest residues. It was assumed that these factors are applicable as emission factors for the open burning of wood. The heating value used for wood for these calculations was 14.8 MJ/kg, which is more representative of the lower moisture content wood burned in residential sources than the heating value in Table 5, applicable to wood-fired boilers. Because a significant amount of carbon is released from natural draft wood combustion in the form of nonmethane organics (e.g. polycylic organic matter, alkanes, aldehydes, ketones, etc.) or retained in the ash, a carbon balance approach for estimating CO_2 as described in Section 2 is not applicable.

CO_2 emission factors for conventional wood stoves were derived from emission tests done for Omni Environmental Services Certification Reports for the Oregon Department of Environmental Quality. Both CO and CO_2 were measured, and for the emission tests reviewed, the ratio of the CO_2/CO emission rates was approximately 4.0. This factor was applied to the CO emission rates obtained from AP-42 to derive an estimate of CO_2 emissions from conventional wood stoves. Similarly, emission tests on appliances with air to fuel ratios characteristic of fireplaces were found to have CO_2/CO ratios in the range of 5 to 6. Therefore, a factor of 5.5 was applied to the CO emission rates for fireplaces and open burning to derive an estimate of the CO_2 rates. The CO_2 emission factor calculated in this manner is significantly lower than an emission factor calculated using the carbon balance method described in Section 2 and accounts for the carbon emitted as non-methane & organics and retained in solids formed during combustion. It should be emphasized that this method of estimating CO_2 is a rough, order-of-magnitude estimate, more appropriate for natural draft wood combustion sources that exhibit incomplete combustion.

The energy input-based emission factors for wood fireplaces were determined from AP-42 factors for NO_x and CO from fireplaces, using the same heating value as for wood pits. No emission factor for CH_4 was readily available. The CO_2 emission factor was calculated using a CO_2 to CO mass ratio of 5.5 using the same method as for wood pits.

The emission factors for wood stoves were converted to an energy output basis using the estimated efficiency of 50 percent and a heating value for wood of 14.8 MJ/kg as discussed. The emission factors for NO_x, CO, and CH_4 were calculated from AP-42 emission factors. The CO_2 emission factor was calculated in the same manner as for wood pits, using a CO_2 to CO mass ratio of 4.

The energy input-based emission factors for CO, CH_4, and NO_x were calculated for propane/butane heaters and furnaces by averaging AP-42 emission factors for butane and propane heaters. The AP-42 factors were converted to an energy input basis using the average heating value for butane and propane from Table 5. The emission factor for CO_2 was calculated using the carbon balance method of Section 2; however, CO and CH_4 emissions are negligible and were not included in the carbon balance.

The coal-fired hot water boiler NO_x and CO emission factors were both calculated from an average of six data points and were converted from a mass to an energy input basis using the heating value for coal from Table 5 (Hughes and DeAngelis, 1982). Emission data for CH_4 were not readily available. The CO_2 emission factor was estimated based on the heating value and carbon content of coal. The emission factors for coal furnaces were determined in the same manner as for coal-fired hot water boilers, except that the NO_x and CO emission factors are based on an average of four data points, and the CO_2 balance includes CO.

The CO emission factor for coal-fired stoves is based on an average of three emission factors for bituminous coal and one emission factor for anthracite coal, converted to an energy input basis using the heating value for coal in Table 5 (Truesdale and Cleland, 1982). An emission factor for CH_4 was not readily available. The emission factor for NO_x is based on an average of emissions data from two sources (Truesdale and Cleland, 1982). Emission of

CO was accounted for in estimating the CO_2 emission factor, using the carbon balance technique described in Section 2.

The CO, NO_x, and CH_4 emission factors for distillate oil furnaces were estimated on an energy output basis from AP-42 emission factors, the heating value for distillate oil from Table 5, and the efficiency for distillate oil furnaces from Table 26. The CO_2 emission factor was calculated based only the carbon content of distillate oil from Table 5; CO and CH_4 have a negligible impact on the CO_2 emission factor.

Finally, the CO, CH_4, and NO_x emission factors for natural gas heaters are based on emission factors for commercial natural gas-fired space heaters (Truesdale and Cleland, 1982). These factors were converted to an energy output basis using the natural gas heating value and the efficiency of natural gas-fired space heaters. The CO_2 emission factor was calculated only from the properties of natural gas.

COMMERCIAL SOURCES

As part of the commercial sources category, 11 energy conversion technologies were evaluated for efficiency and emissions. These sources include technologies for burning wood, natural gas, residual oil, distillate oil, MSW, coal, shale oil, and agricultural wastes.

The efficiency and emission factors for each source are presented in Table 27. To the right of each emission factor is the emission factor quality rating. The last column contains the code for control technologies, which are presented in Table 28.

Efficiency

Efficiency estimates were developed for all commercial emission sources with the exception of open burning and incineration sources. These sources are not generally intended for energy conversion; instead, they are used for waste disposal. Because generally no energy is recovered from the open burning or incineration of waste, and because the combustion of these wastes is for the purpose of waste disposal, the emission factors for these sources are in terms of amount of pollutant emitted per unit mass of waste.

TABLE 27. COMMERCIAL SOURCE PERFORMANCE

Source	Efficiency (%)	Emissions Factors (g/GJ end-use energy) and Data Quality Ratings (A - E)					Controls[a]
		CO_2	CO	CH_4	N_2O	NO_x	
Wood Boilers	67.5	138,000 C	280 D	21 E	6 E	47 C	R25
Gas Boilers	80.9	61,800 A	10.6 A	1.4 D	2.7 E	53 A	R25, R26, R28, R30
Residual Oil Boilers	84.9	86,000 A	19 A	1.8 A	52 E	183 A	R25, R27, R29
Distillate Oil Boil.	82.8	85,000 B	18 A	0.8 A	18 E	74 A	R25, R26, R28, R30
MSW Boilers	55.0	157,000 D	32 B	N/A	N/A	800 C	R25
Coal Boilers	75.9	135,000 C	244 E	13 E	74 E	295 E	R25, R27, R29
Shale Oil Boilers	84.9	86,000 E	19 E	1.8 E	52 E	208 E	R25, R27, R29
Open burning - MSW	n/appl	900 kg/Mg C	42 kg/Mg C	6.5 kg/Mg C	N/A	3 kg/Mg C	
Open burning-Agric.	n/appl	1,570 kg/Mg C	58 kg/Mg C	9 kg/Mg C	N/A	N/A	
Inciner.-high effic.	n/appl	970 kg/Mg C	5 kg/Mg B	N/A	N/A	1.5 kg/Mg B	
Inciner.-Low effic.	n/appl	960 kg/Mg C	10 kg/Mg B	N/A	N/A	1 kg/Mg B	

[a] Control codes are defined in Table 28.

TABLE 28. RESIDENTIAL AND COMMERCIAL EMISSION CONTROLS COST AND PERFORMANCE

Technology	Code	Efficiency Loss (%)	Cost ($/J End-Use)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
Catalytic Woodstove	R1	-44	N/A	-35	90	90	N/A	-27	1985
Non-Catalytic MCS	R2	-30	N/A	-6	15	50	N/A	-5	1985
Flame Ret. Burn. Hd.	R6	-9	1.5E-11	neg	28	N/A	N/A	N/A	
Contr. Mix. Burn. Hd	R7	-7	1.3E-11	neg	43	N/A	N/A	44	
Integr. Furn. Syst.	R8	-12	6.9E-11	neg	13	N/A	N/A	69	
Blueray Burn./Furn.	R9	-12	2.8E-11	neg	74	N/A	N/A	84	
M.A.N. Burner	R10	-13	N/A	N/A	N/A	N/A	N/A	71	1980
Radiant Screens	R11	-7	N/A	neg	62	N/A	N/A	55	
Secondary Air Baffle	R12	N/A	N/A	neg	16	N/A	N/A	40	
Surface Comb. Burner	R13	N/A	N/A	neg	55	N/A	N/A	79	
Amana HTM	R14	-21	5.1E-11	neg	-55	N/A	N/A	79	
Modulating Furnace	R15	-7	4.4E-11	N/A	N/A	N/A	N/A	32	
Pulse Combustor	R16	-36	9.7E-11	N/A	N/A	N/A	N/A	47	
Catalytic Combustor	R17	-29	4.8E-11	N/A	N/A	N/A	N/A	86	
Replace Worn Units	R18	N/A	2.5E-10	neg	65	N/A	N/A	N/A	
Tuning, Seas. Maint.	R19	-2	1.0E-10	neg	16	N/A	N/A	N/A	
Red. Excess. Firing	R20	-19	1.3E-11	neg	14	N/A	N/A	N/A	
Red Fir w/ new ret b	R21	-40	8.3E-11	neg	14	N/A	N/A	N/A	
Pos. Chimney Dampers	R22	-8	5.7E-11	neg	11	N/A	N/A	N/A	
Inc. therm. anticip.	R23	-1	minimal	neg	43	N/A	N/A	N/A	
Night therm. cutback	R24	-15	minimal	neg	17	N/A	N/A	N/A	
Low Excess Air	R25	-0.8	-7.0E-09	N/A	N/A	N/A	N/A	15	1970
Flue Gas Recirculat.	R26	0.6	N/A	N/A	N/A	N/A	N/A	50	1975
Over-fire Air	R27	1	N/A	N/A	N/A	N/A	N/A	20	1970
Over-fire Air	R28	1	N/A	N/A	N/A	N/A	N/A	30	1970
Low NOx Burners	R29	0.6	N/A	N/A	N/A	N/A	N/A	40	1980
Low NOx Burners	R30	0.6	N/A	N/A	N/A	N/A	N/A	50	1980

Efficiencies for the other sources will be discussed in the order in which they appear in Table 26.

Efficiency data were not readily available for commercial wood-fired boilers; an efficiency for industrial wood-fired boilers of 67.5 percent was assumed applicable. The efficiency of commercial boilers is taken to be 80.9 percent for natural gas based on an average of 16 data points. For residual oil boilers, the efficiency is 84.9 percent based on an average of 13 points. Distillate oil-fired boilers are assumed to have an efficiency of 82.8 percent based an average of 5 points. Based on an average of nine points, coal-fired commercial boilers are assumed to have an efficiency of 75.9 percent. An efficiency of 55 percent, based on small modular incinerators with heat recovery, is assumed for MSW commercial boilers (Shindler, 1987). The efficiency of shale oil-fired commercial boilers is assumed to be the same as that for residual oil-fired boilers.

Emission Factors

The emission factors for NO_x, CO, and CH_4 were taken directly from AP-42 and converted to energy units, except for open burning and incineration, using the appropriate heating value from Table 5 and efficiency from Table 26, except where noted. The emissions of N_2O were estimated to be 5 percent of NO_x emissions for natural gas, 25 percent for oil and coal, and 13 percent for wood, as discussed in previous sections for utility and industrial boilers. No data were available for emissions of N_2O from MSW or agricultural waste. CO_2 emission factors are calculated only from fuel properties using the technique outlined in Section 2 except for open burning and incineration. Both CO and CH_4 included in the carbon balance for open burning, and CO was included in the carbon balance for incineration.

The emission factor for CO for wood-fired boilers is taken from a the NAPAP emission inventory (Shindler, 1987). For MSW-fired commercial boilers, the emission factor for CO is assumed to be the same as for industrial small modular MSW-fired boilers. No data were available for the emission of CH_4 from MSW boilers, or from open burning or incineration of waste. The NO_x emission factor for MSW-fired boilers is based on the emission factor for solid waste-fired controlled air units in AP-42.

For coal-fired boilers, the emission factors for NO_x, CO, and CH_4 were calculated using a U.S. population-weighted average of AP-42 emission factors for overfeed stoker, underfeed stoker, and spreader stoker coal-fired boilers. These three firing types comprise 33 percent of the total U.S. commercial boiler capacity (Devitt et al., 1979). Emission factors for firetube and cast iron industrial boilers, which comprise most of the remaining capacity, were not readily available.

As a rough estimate, the emission factors for shale oil-fired boilers were assumed to be the same as those for residual oil-fired boilers.

The NO_x, CO, and CH_4 emission factors for open burning of MSW were taken directly from AP-42 factors. The CO_2 emission factor was calculated including both CO and CH_4 in the carbon balance using the method outlined in Section 2. In a similar manner, the emission factors for open burning of agricultural waste were derived; however, an emission factor for NO_x was not readily available. The CO and CH_4 emission factors are based on the "unspecified" field crops category in AP-42. Since carbon contents for various field crops were unavailable except for bagasse, an average carbon content of 46 percent for dry bagasse was used to calculate a CO_2 emission factor (U.S. EPA, 1982[b]). Both CO and CH_4 were included in the carbon balance as discussed in Section 2.

Emission data for CH_4 from incinerators firing MSW were not readily available. The CO_2 emission factors for both multi-stage and single chamber incinerators are based on the carbon content of MSW and a carbon balance including CO.

RESIDENTIAL AND COMMERCIAL SOURCE EMISSION CONTROL TECHNOLOGIES

Table 28 includes 27 control technologies, the first 21 of which are applicable to residential emission sources, and the last 6 of which are applicable to commercial sources. Table 28 includes the code for each technology, the efficiency penalty, the emission reduction efficiency for each pollutant, and the availability date.

Efficiency Penalty

Most of the controls for residential sources result in an increase in the combustion efficiency of the sources to which they are applied. Catalytic wood stoves and noncatalytic modified combustion wood stoves have efficiency increases of 44 and 30 percent, respectively, over conventional wood stoves. Low excess air, flue gas recirculation, overfire air, and low NO_x burners may be applied to several of the commercial emission sources. Low excess air typically results in about a 0.8 percent increase in efficiency, whereas the other controls typically decrease the source efficiency as indicated in Table 28 (Castaldini et al., 1981). All other controls in Table 28 for which efficiency penalty information was readily available result in an increase in the source thermal efficiency (Castaldini et al., 1981).

Reduction Efficiency

Unless otherwise noted, the reduction efficiencies for each control technology were estimated from Castaldini et al. (1981). For most of the control technologies, the CO reduction (or increase) does not significantly impact the emission factor for CO_2. An entry of "negligible" for the CO_2 emission factor indicates that CO_2 emissions, based on a carbon balance, do not vary more than 0.05 percent from the original value due to the application of the control technology.

The catalytic and noncatalytic modified combustion wood stove technologies significantly impact the emissions of NO_x, CH_4, and CO (U.S. EPA, 1982b). The emission of CO_2 for these sources is also significantly impacted. The increase in the emission of CO_2 for these two controls was estimated by assuming that the CO reduced by the controls is converted to CO_2.

The only emission reduction data readily available for low excess air, flue gas recirculation, overfire air, and low NO_x burners applied to commercial sources were the reduction efficiency for NO_x (U.S. EPA, 1982b).

Cost

The basis for the annualized control technology costs presented in Table 28 is given in Table 29. Table 29 includes the capacity of the source for which control costs were calculated, the capital cost, and the annual cost of the control. These costs were annualized using a life of 15 years, and an interest rate of 10 percent. All control costs were converted to an energy output basis using the appropriate source efficiency from Table 26. All costs exclude fuel except for low excess air (R25), for which nonfuel costs were not readily available.

TABLE 29. RESIDENTIAL AND COMMERCIAL EMISSION CONTROL COST

Technology	Source Capacity	Capital Cost ($)	Annual Cost ($)
Flame Retention Burners	29.3 kW	75	--
Controlled Mix Burner Hood	29.3 kW	62	--
Integrated Furnace System	29.3 kW	363	--
Blueray Burner/Furnace	29.3 kW	145	--
Amana HTM	29.3 kW	290	--
Modulating Furnace	29.3 kW	218	--
Pulse Combustor	29.3 kW	653	--
Catalytic Combustor	29.3 kW	290	--
Replace Worn Units	29.3 kW	1,196	--
Tuning	29.3 kW	--	71
Reduced Excessive Firing Firing Capacity - Conventional Burner	29.3 kW	75	--
Reduced Excessive Firing Capacity - New Retention Burner	29.3 kW	558	--
Positive Chimney Dampers	29.3 kW	290	--
Low Excess Air	2.9 MW	7,000	

Source: Castaldini et al., 1981; Truesdale and Cleland, 1982.

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GLOSSARY

Agric	Agricultural
AFBC	Atmospheric Fluidized Bed Combustion
AP-42	Compilation of Air Pollutant Emission Factors, Vols. I and II. U.S. EPA AP-42
bbl crude well	Barrels (42 gallons) of crude oil from oil
BOOS	Burners Out of Service
C	Carbon
Cat Mod. Comb. Stove	Catalytic Modified Combustion Stove
Coal-FB Comb Cycl	Coal - Fluidized Bed Combined Cycle
Coal - PC Cyclone	Coal - Pulverized Coal Cyclone
Comb.	Combustion
Contr. Mix. Burn. Hd.	Controlled Mixing Burner Head
CF	Capacity Factor
CNG	Compressed Natural Gas
CRF	Capital Recovery Factor
Distil. Oil	Distillate Oil
FBC	Fluidized Bed Combustion
Effic.	Efficiency
FGR	Flue Gas Recirculation
Fir.	Firing
Flame Ret. Burn. Hd.	Flame Retention Burner Head
FTP	Federal Test Procedure
Gas Turbine Comb. C.	Gas Turbine Combined Cycle
Gas Turbine Simp. C.	Gas Turbine Simple Cycle
GJ	Giga Joule (10^9 Joules)
HC	Hydrocarbons

GLOSSARY (Continued)

HDDV	Heavy Duty Diesel Vehicle
HDGV	Heavy Duty Gasoline Vehicle
IC Engine	Internal Combustion Engine
Inc. therm. anticip.	Increased Thermostat Anticipator Setting
Inciner. - high effic.	High Efficiency Incinerators
Inciner. - low effic.	Low Efficiency Incinerators
In-Situ Retorting	Underground process for removing shale oil from shale
HV =	Heating Value (Higher)
LDDV	Light Duty Diesel Vehicle
LDGV	Light Duty Gasoline Vehicle
LEA	Low Excess Air
LNB	Low NO_x Burner
MSW	Municipal Solid Waste
MW	Megawatt
N/A	Not Available
NAPAP	Criteria Pollutant Emission Factors for the 1985 NAPAP Emissions Inventory. EPA-600/7-87-015
neg	Negligible
Night therm. cutback	Night Thermostat Cutback
NSCR	Non-Selective Catalytic Reduction
OFA	Overfire Air
Oil Shale Retorting	The process for extracting shale oil from the shale with heat
Pos. Chimney Dampers	Positive Chimney Dampers
PSC	Pre-Stratified Charge
RDF	Refuse Derived Fuels

GLOSSARY (Continued)

Red. Fir w/new ret b.	Reduced excessive firing capacity with new retention burner
Retrof.	Retrofit
Refinery CH_4 Used	Oil refinery scenario in which natural gas from wells is routed to heat generation
Refin. Nat. Gas	Refinery Natural Gas
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
TF	Tangentially Fired Coal Fired Boiler
THC	Total Hydrocarbons
Tuning, Seas. Maint.	Tuning and Seasonal Maintenance